March 8, 2023

Alaska Department of Environmental Conservation
Air Permits Program
Attention: Permit Intake Clerk
610 University Avenue
Fairbanks, Alaska 99709-3643

Subject: Badami Development Facility – Permit Renewal Application
Title V Air Quality Operating Permit Number AQ0417TVP03

Dear Permit Intake Clerk,

Savant Alaska, LLC (Savant) is submitting the enclosed Title V Air Quality Operating Permit Application under 18 Alaska Administrative Code (AAC) 50.326(c) to renew the existing Title V Permit Number AQ0417VP03 for the Badami Development Facility. This submittal also meets the requirements of Condition 78 of the operating permit.

The attached renewal application contains applicable Series Forms A, B, D, and E. The following forms are not provided.

- Form A1-R. No supplemental information is submitted at this time.
- Form A2 – Stationary Source Description. No changes to the Form A2 data are necessary.
- Form A3 – Operating Scenario Description. No changes to the Form A3 data are necessary.
- Form Series C. The source does not employ pollution control devices.
- Form D1 and D2. As allowed by the Department, D1 and D2 form data are submitted in spreadsheet format.
- Form E2. No Permit-to-Operate and Minor Permit Condition Change Requests are proposed.
- Form E3. No Title V Condition Change Requests are proposed.

A copy of the 2022 Annual Compliance Certification for Title V Permit Number AQ0417TVP03 is attached in section A. A copy of the current Title V Operating Permit Number AQ0417TVP03 and Minor Source Permit Number AQ0417MSS05, AQ0417MSS06, and AQ0417MSS07, Revision 1 are attached to the permit renewal application.

If you have any questions, please contact me at 907-334-6745, or the application contact, Chris Lindsey (SLR), at 907-264-6916.

Sincerely,

David Pascal
Chief Operating Officer

cc: EPA-Region 10
Chris Lindsey, SLR International Corporation

Enclosure: Title V Permit Renewal Application, hard copy and electronic copy

Application for Renewal of an Air Quality Operating Permit

Badami Development Facility

Prepared for: Savant Alaska, LLC

March 2023

Application for Renewal of an Air Quality Operating Permit for Badami Development Facility

Prepared for:

Savant Alaska, LLC

188 Northern Lights Blvd. Suite 510
Anchorage, AK 99503

prepared by

SLR INTERNATIONAL CORPORATION

2700 Gambell Street, Suite 200
Anchorage, Alaska 99503
(907) 222-1112

March 2023

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SECTION A
STATIONARY SOURCE

Form A1: Stationary Source (General Information)

Form A4: Title V Air Operating Permit Renewal Application Information

Attachments: Compliance Certification

FORM A1
Stationary Source (General Information)

GENERAL INFORMATION

1. Permittee:

Permittee Name: ***Savant Alaska, LLC***

Mailing Address Line 1: 188 Northern Lights Blvd. Suite 510

Mailing Address Line 2

City: Anchorage State: AK Zip Code: 99503

2. Stationary Source Name: Badami Development Facility

3. Stationary Source Physical Address:

Physical Address Line 1: Badami Unit, North Slope

Physical Address Line 2 :

City: State: AK Zip Code:

4. Location: : UTM Zone 6, Northing 7782.6 km, Easting 494.6 km Latitude: 70° 09' 03.62" N Longitude: 147° 05' 50.05" W

5. Primary SIC Code: 1311 SIC Code Description: Crude Oil and Natural Gas Production ***Primary NAICS Code:*** 211120-Crude Petroleum Extraction 211130 Natural Gas Extraction

6. Current/Previous Title V Air Permit No.: AQ0417TVP03 Expiration Date: September 13, 2023

7. Does this application contain confidential data? ☐ Yes ☒ No

8. APPLICATION IS BEING MADE FOR:

☐ Initial Title V Permit for this Stationary Source ☐ Modify Title V Permit (currently permitted) ☒ Title V Permit Renewal

9. CONTACT INFORMATION (Attach additional sheets if needed)

Owner:	***Operator:***
Name/Title: Savant Alaska, LLC	Name/Title: Savant Alaska, LLC
Mailing Address Line 1: 188 Northern Lights Blvd. Suite 510	Mailing Address Line 1: 188 Northern Lights Blvd. Suite 510
Mailing Address Line 2	Mailing Address Line 2
City: Anchorage State: AK Zip Code: 99503	City: Anchorage State: AK Zip Code: 99503
Permittee's Responsible Official:	***Designated Agent:***
Name/Title: David Pascal / Chief Operating Officer	Name/Title Stoel Rives LLP, Ramona L. Monroe, Attorney
Mailing Address Line 1: 188 Northern Lights Blvd. Suite 510	Mailing Address Line 1 600 University Street, Suite 3600
Mailing Address Line 2	Mailing Address Line 2
City: Anchorage State: AK Zip Code: 99503	City: Seattle State: WA Zip Code: 98101-4109
Stationary Source and Building Contact:	***Fee Contact:***
Name/Title: Lynnette Peluso, Regulatory & Compliance Lead	Name/Title: Lynnette Peluso, Regulatory & Compliance Lead
Mailing Address Line 1: 188 Northern Lights Blvd. Suite 510	Mailing Address Line 1: 188 Northern Lights Blvd. Suite 510
Mailing Address Line 2	Mailing Address Line 2
City: Anchorage State: AK Zip Code: 99503	City: Anchorage State: AK Zip Code: 99503
Phone: 907-433-3829 Email: lpeluso@glacieroil.com	Phone: 907-433-3829 Email: lpeluso@glacieroil.com
Permit Contact:	***Person or Firm that Prepared Application:***
Name/Title: Lynnette Peluso, Regulatory & Compliance Lead	Name/Title: Chris Lindsey, SLR Consulting
Mailing Address Line 1: 188 Northern Lights Blvd. Suite 510	Mailing Address Line 1: 2700 Gambell Street
Mailing Address Line 2	Mailing Address Line 2: Suite 200
City: Anchorage State: AK Zip Code: 99503	City: Anchorage State: AK Zip Code: 99503
Phone: 907-433-3829 Email: lpeluso@glacieroil.com	Phone: 907-264-6916 Email: clindsey@slrconsulting.com

10. STATEMENT OF CERTIFICATION

Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.

Name of Responsible Official (typed): David Pascal Title: Chief Operating Officer

X Signature (blue ink): Date: March 7, 2023

FORM A4

Title V Air Operating Permit Renewal Application Information

Permit Number: AQ0417TVP03

1.	Permit Contact: Name	Lynette Peluso, Regulatory & Compliance Lead
	Title	Regulatory & Compliance Manager
	Mailing Address Line 1	601 W. 5th Avenue, Suite 310
	Mailing Address Line 2	Anchorage, AK 99501
	Phone Number	907-433-3829
	Email	lpeluso@glacieroil.com
2.	Were there any changes to stationary source General Information (Form A1)? If yes, complete and submit a Form A1.	Yes, Form A1 is included in Attachment A.
3.	Were there any changes to the stationary source description (Form A2)? If yes, complete and submit a Form A2.	No.
4.	Were there any off-permit changes? Reference any notifications provided to the Department, and attach copies of the notifications.	No.
	If yes, integrate changes into renewal permit? [if no, explain]	Not applicable.
5.	Have any Alaska Title I permits been issued to the stationary source since the most recent Title V permit or revision issuance?	No.
	If yes, integrate changes into renewal permit? [If yes, please list. If no, explain]	Not applicable.
6.	Will there be any changes to the operating scenario(s)? [if yes, describe and attach Form A3]	No.
7.	Will there be any new, modified, or reconstructed emission units or air pollution control equipment? [if yes, attach appropriate forms from Form Series B, C, D, and E]	No.
8.	Are the current emissions units correctly identified and defined in the permit? [if no, attach appropriate forms from Form Series B, C, D, and E]	Yes, there was a correction made to the rating of an insignificant unit. See Form B.
9.	Does the CAM rule [40 CFR Part 64] apply to any of the emissions units? [if yes, review the guidance provided for CAM in the Form A4 instructions for this item]	No.
10.	Does the accidental release prevention regulation [40 CFR Part 68] apply to the facility? [if yes, provide the appropriate regulatory applicability document in detail.]	No.
11.	Are there any other new applicable requirements? [if yes, list the new applicable requirements, emissions units, and attach the appropriate Series E Form]	No.

12.	Are there any requested changes in the assessable potential to emit other than those identified in item 9 above? [if yes, answer the following]	No.
	Are the changes a result of having better emissions information such as a new emission factor from a recent source test? [if yes, complete and attach any applicable emissions forms from Series D. Attach additional information as necessary to fully document.]	No.
	Are the changes due to an increase in production? [if yes, complete and attach the applicable emissions form from Series D. Attach additional information as necessary to fully document.]	No.
13.	Is the stationary source in compliance with all of the conditions of the current permit? If yes, attach a compliance certification. If no, attach a compliance schedule and/or actions taken for any out-of-compliance emission units.	Yes, the 2022 Annual Compliance Certification is included in Attachment F.
14.	Are there any requested changes to testing and/or monitoring conditions? [if yes, identify the condition, the requested change, and the reason. Attach additional information as necessary to fully document.]	No.
15.	Are there any requested changes to monitoring conditions other than those being replaced by CAM? [if yes, identify the condition, the requested change, and the reason. Attach additional information as necessary to fully document.]	Yes, see Form E1.
16.	Are there any requested changes to recordkeeping conditions? [if yes, identify the condition, the requested change, and the reason. Attach additional information as necessary to fully document.]	Yes, see Form E1.
17.	Are there any requested changes to reporting conditions? [if yes, identify the condition, the requested change, and the reason. Attach additional information as necessary to fully document.]	Yes, see Form E1.
18.	Are there any requested changes to the non-applicable requirements (i.e. permit shield)? [if yes, identify the emission unit, the requested change, and the reason in the appropriate Series B and/or D form. If the change applies stationary source-wide, complete the appropriate Series E form. Attach additional information as necessary to fully document.]	No.
19.	Are there any other requested changes to any condition? [if yes, identify the condition, the requested change, and the reason. Attach	Yes, see B Forms and Form E1. Requested changes to reflect current Standard Permit Conditions.

	additional information as necessary to fully document.]	

Statement of Certification:

Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.

David Pascal	Chief Operating Officer / COO
Name of Responsible Official	**Title**
Signature (blue ink)	March 7, 2023
	Date

2022 Annual Compliance Certification

Annual Compliance Certification
Permit No. AQ0417TVP03
Badami Development Facility
January 1-December 31, 2022

Condition Number	Condition Text	Method Used to Determine Compliance Status	Compliance Status	Permit Deviations Identified During Calendar Year
Section 3. State Requirements				
Visible Emissions Standards				
1	**Industrial Process and Fuel-Burning Equipment Visible Emissions.** The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from EU IDs 8, 420a, 421a, 500, 501, 503, 505, and 507 listed in Table A to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.	Records Review and Interview with Responsible Personnel	Continuous	None
1.1	For EU ID 8, monitor, record, and report in accordance with Condition 21.4.	Records Review	Continuous	None
1.2	For EU IDs 420a and 421a, monitor, record and report in accordance with Conditions 2 through 4.	Records Review	Continuous	None
1.3	For EU IDs 500, 501, 503, and 505, burn only fuel gas as fuel. Monitoring for these emission units shall consist of a statement in each operating report under Condition 71 whether each of these emission units fired only fuel gas during the period covered by the report. Report under Condition 70 if any fuel other than fuel gas is burned.	Interview with Responsible Personnel	Continuous	None
1.4	For EU ID 507, monitor, record and report in accordance with Condition 5.	Records Review	Continuous	None
Visible Emissions Monitoring, Recordkeeping and Reporting *Liquid Fuel-Fired Emission Units (EU IDs 420a and 421a)*				
2	**Visible Emissions Monitoring. As required by Conditions 1.2 or 18.4a, t**he Permittee shall observe the exhaust of EU IDs 420a and 421a for visible emissions using the Method 9 Plan under Condition 2.3.	Records Review	Continuous	None
2.1	In the event of replacement of any of EU IDs 420a and 421a, the Permittee shall observe the exhaust of the newly installed emissions unit(s) using the Method 9 Plan under Condition 2.3.	Records Review and Interview with Responsible Personnel	Continuous	None
2.2	The Permittee may for each unit elect to continue the visible emissions monitoring schedule that remain in effect from a previous permit.	Records Review	Continuous	None

Annual Compliance Certification
Permit No. AQ0417TVP03
Badami Development Facility
January 1-December 31, 2022

Condition Number	Condition Text	Method Used to Determine Compliance Status	Compliance Status	Permit Deviations Identified During Calendar Year
2.3	**Method 9 Plan.** For all 18-minute observations in this plan, observe exhaust, following 40 C.F.R. 60, Appendix A-4, Method 9, adopted by reference in 18 AAC 50.040(a), for 18 minutes to obtain 72 consecutive 15-second opacity observations.	Records Review	Continuous	None
2.3a	**First Method 9 Observation**. Except as provided in Condition 2.2, observe the exhaust of EU IDs 420a and 421a for 18 minutes within six months after the issue date of this permit. i) For any of EU IDs 420a and 421a that is replaced during the term of this permit, observe exhaust for 18 minutes within 30 days of startup.			
2.3b	**Monthly Method 9 Observations.** After the first Method 9 observation conducted under Condition 2.3.a, perform 18-minute observations at least once in each calendar month that the emissions unit operates.			
2.3c	**Semiannual Method 9 Observations.** After at least three monthly observations under Condition 2.3.b, unless a six-minute average opacity is greater than 15 percent and one or more observations are greater than 20 percent, perform observations: (i) within six months after the preceding observation, or (ii) for an emissions unit with intermittent operations, during the next scheduled operation immediately following six months after the preceding observation.			
2.3d	**Annual Method 9 Observations.** After at least two semiannual 18-minute observations under Condition 2.3c, unless a six-minute average is greater than 15 percent and one or more individual observations are greater than 20 percent, perform observations: (i) Within twelve months after the preceding observation; or (ii) For an emissions unit with intermittent operations, during the next scheduled operation immediately following twelve months after the preceding observation.			
2.3e	**Increased Method 9 Frequency.** If a six-minute average opacity is observed during the most recent set of observations to be greater than 15 percent and one or more observations are greater than 20 percent, then increase or maintain the observation frequency for that emissions unit to at least monthly intervals as described in Condition 2.3.b, and continue monitoring in accordance with the Method 9 Plan.			
3	**Visible Emissions Recordkeeping.** When visible emissions monitoring is conducted, the Permittee shall keep records as follows:	Records Review	Continuous	None
3.1	For all Method 9 observations, a. the observer shall record: (i) the name of the stationary source, emissions unit and location, emissions unit type, observer's name and affiliation, and the date on the Visible Emissions Observation Form in Section 11; (ii) the time, estimated distance to the emissions location, sun location, approximate wind direction, estimated wind speed, description of the sky condition (presence and color of clouds), and plume background, and operating rate (load or fuel consumption rate or best estimate, if unknown) on the sheet at the time opacity observations are initiated and completed; (iii) the presence or absence of an attached or detached plume and the approximate distance from the emissions outlet to the point in the plume at which the observations are made; (iv) opacity observations to the nearest five percent at 15-second intervals on the Visible Emissions Observation Form in Section 11, and (v) the minimum number of observations required by the permit; each momentary observation recorded shall be deemed to represent the average opacity of emissions for a 15-second period.			
3.2	To determine the six-minute average opacity, divide the observations recorded on the record sheet into sets of 24 consecutive observations; sets need not be consecutive in time and in no case shall two sets overlap; for each set of 24 observations, calculate the average by summing the opacity of the 24 observations and dividing this sum by 24; record the average opacity on the sheet.			
3.3	Calculate and record the highest six-minute and 18-consecutive-minute averages observed.			
3.4	The records may be kept in electronic format.			
4	**Visible Emissions Reporting**. When visible emissions monitoring is conducted, the Permittee shall report visible emissions as follows:	Records Review	Continuous	None
4.1	Include in each operating report under Condition 71: a. copies of the observation results (i.e. opacity observations) for each emissions unit, except for the observations the Permittee has already supplied to the Department; and b. a summary to include: (i) number of days observations were made; (ii) highest six- and 18-consecutive-minute average opacities observed; and (iii) dates when one or more observed six-minute average opacities were greater than 20 percent; and c. a summary of any monitoring or recordkeeping required under Conditions 2 and 3 that was not done.			
4.2	Report under Condition 70: a. the results of Method 9 observations that exceed 20 percent average opacity for any six-minute period; and b. if any monitoring under Condition 2 was not performed when required, report within three days of the			
Flares (EU ID 10)				
5	**Visible Emissions MR&R.** The Permittee shall observe one daylight flare event within 12 months of the preceding flare event observation. If no event exceeds 1 hour within the 12month period, then the Permittee shall observe the next daylight flare event.	Records Review	Continuous	None
5.1	Monitor the flare for visible emissions for 18 minutes during flare events using Method 9.			

5.2	Record the following information for observed events:
	a. the flare(s) EU ID number;
	b. results of the Method 9 observations;
	c. reason(s) for flaring;
	d. date, beginning and ending time of event; and
	e. volume of fuel gas and produced gas flared.			

5.3	The records may be kept in electronic format.			
5.4	Attach copies of the records required by Condition 5.2 in the operating report required by Condition 71 for the period covered by that report.			
5.5	Report under Condition 70 whenever the opacity standard in Condition 1 is exceeded.			

Annual Compliance Certification
Permit No. AQ0417TVP03
Badami Development Facility
January 1-December 31, 2022

Condition Number	Condition Text	Method Used to Determine Compliance Status	Compliance Status	Permit Deviations Identified During Calendar Year
Particulate Matter Emissions Standards				
6	**Industrial Process and Fuel-Burning Equipment Particulate Matter.** The Permittee shall not cause or allow particulate matter (PM) emitted from EU IDs 8, 420a, 421a, 500, 501, 503, 505, and 507 listed in Table A to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.	Records Review	Continuous	None
6.1	For EU ID 8, monitor, record, and report in accordance with Condition 21.4.	Records Review and Interview with Responsible Personnel	Continuous	None
6.2	For EU IDs 420a and 421a, monitor, record and report in accordance with Conditions 7 through 9.	Records Review	Continuous	None
6.3	For EU IDs 500, 501, 503, and 505, burn only fuel gas as fuel. Monitoring for these emissions units shall consist of a statement in each operating report under Condition 71 that each of these emissions units fired only fuel gas during the period covered by the report. Report under Condition 70 if any fuel other than fuel gas is burned.	Records Review	Continuous	None
6.4	For EU ID 507, the Permittee shall comply with Condition 5.	Records Review	Continuous	None
PM Monitoring, Recordkeeping and Reporting Liquid Fuel-Fired Engines (EU IDs 420a and 421a)				
7	**Particulate Matter Monitoring for Diesel Engines.** The Permittee shall conduct source tests on EU IDs 420a and 421a to determine the concentration of particulate matter in the exhaust of each emissions unit, as follows:	Records Review	Continuous	None
7.1	Conduct the particulate matter source test or make repairs in accordance with Condition 7.1 if a. Method 9 observations, as calculated under Condition 3.3, result in an 18 minute average opacity greater than 20 percent; or b. for an emissions unit with an exhaust stack diameter that is less than 18 inches, Method 9 observations, as calculated under Condition 3.3, result in an 18minute average opacity that is greater than 15 percent, unless the Department has waived this requirement in writing.			
7.2	Conduct the PM source test or make repairs according to Condition 7.1 if: a. 18 consecutive minutes of Method 9 observations result in an 18-minute average opacity that is greater than 20 percent; or b. For an emission unit with exhaust stack diameter that is less than 18 inches, 18 consecutive minutes of Method 9 observations result in an 18-minute average opacity that is greater than 15 percent and not more than 20 percent, unless the Department has waived this requirement in writing.			
7.3	During each one-hour particulate matter source test run, observe the exhaust for 60 minutes in accordance with Method 9 and calculate the highest 18-minute average opacity measured during each one-hour test run. Submit a copy of these observations with the source test report.			
7.4	The particulate matter source test requirements in Conditions 7.1 and 7.2 are waived for an emissions unit if a source test on that unit has shown compliance with the particulate matter standard during this permit			
8, 8.1, & 8.2	**Particulate Matter Recordkeeping.** The Permittee shall comply with the following: 8.1. Keep records of the results of any source test and visible emissions observations conducted under Condition 7. 8.2. In the event of replacement of any of EU IDs 420a and 421a, record the exhaust stack diameter of the replacement unit.	Records Review	Continuous	None
9	**Particulate Matter Reporting for Diesel Engines.** The Permittee shall report as follows:	Records Review	Continuous	None
9.1	Report under Condition 70 a. if the results of any source test exceed the particulate matter emissions limit in Condition 6; or b. if one of the criteria of Condition 7.2 was exceeded and the Permittee did not comply on time with either Condition 7.1.a or 7.1.b. Report the deviation within 24 hours of the date compliance with Condition 7.1 was required; c. observations in excess of the threshold of Condition 7.2.b within 30 days of the end of the month in which the observations occur.			
9.2	In each operating report under Condition 71, include: a. the dates, EU ID(s), and results when an observed 18-minute average opacity was greater than an applicable threshold in Condition 7.2. b. a summary of the results of any particulate matter testing conducted under Condition 7; and c. copies of any visible emissions observation results greater than the thresholds of Condition 7.2, if they were not already submitted.			

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Permit No. AQ0417TVP03
Badami Development Facility
January 1-December 31, 2022

Condition Number	Condition Text	Method Used to Determine Compliance Status	Compliance Status	Permit Deviations Identified During Calendar Year
9.3	In the event of replacement of any of EU IDs 420a and 421a, report the stack diameter recorded in Condition 8.2 in the next operating report under Condition 71 immediately following installation of the replacement unit.	Records Review and Interview with Responsible Personnel	Continuous	None
Section 3. State Requirements				
10	**Sulfur Compound Emissions.** In accordance with 18 AAC 50.055(c), the Permittee shall not cause or allow sulfur compound emissions, expressed as SO2, from EU IDs 8, 420a, 421a, 500, 501, 503, 505, and 507 listed in Table A to exceed 500 parts per million (ppm) averaged over three hours.	Records Review	Continuous	None
Fuel Oil (EU IDs 8, 420a and 421a)				
10.1	For EU IDs 8, 420a and 421a, to ensure compliance with Condition 10, the Permittee shall comply with the fuel sulfur content limit of 0.15 percent by weight as specified in Condition 14.6 a. The Permittee shall do one of the following for each shipment of fuel: (i) If the fuel grade requires a sulfur content less than the 0.15 percent by weight limit, keep receipts that specify fuel grade and amount received; or (ii) If the fuel grade does not require a sulfur content less than the 0.15 percent by weight limit, keep receipts that specify fuel grade and amount, and (A) test the fuel for sulfur content using an appropriate method listed in 18 AAC 50.035(b)-(c) or 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1); or (B) obtain test results showing the sulfur content of the fuel from the supplier or refinery; the test results must include a statement signed by the supplier or refinery of what fuel they represent.	Records Review	Continuous	None
10.2	The Permittee shall report as follows: a. Include in each operating report required by Condition 71, records obtained under Condition 10.1.a. b. Report in accordance with Condition 70, whenever the fuel combusted causes sulfur compound emissions to exceed the standard of Condition 10. When reporting under this condition, include the calculated SO2 emissions in ppm using Method 19 of 40 C.F.R. 60, Appendix A-7, adopted by reference in 18 AAC 50.040(a).	Records Review	Continuous	None
North Slope Liquid Fuel (EU IDs 8, 420a and 421a)				
10.3	For liquid fuel from a North Slope topping plant, the Permittee shall obtain from the topping plant the results of a monthly fuel sulfur analysis.	Records Review	Continuous	None
10.4	The Permittee shall report as follows: a. Include in the operating report required by Condition 71, a list of the sulfur content measured for each month covered by the report. b. Report in accordance with Condition 70, whenever the fuel combusted causes sulfur compound emissions to exceed the standard of Condition 10. When reporting under this condition, include the calculated SO2 emissions in ppm using Method 19 of 40 C.F.R. 60, Appendix A-7, adopted by reference in 18 AAC 50.040(a).	Records Review	Continuous	None
Fuel Gas (EU IDs 500, 501, 503, 504, 505, and 507)				
10.5	To ensure compliance with Condition 10, the Permittee shall comply with the fuel sulfur content limit of 250 parts per million by volume (ppmv) hydrogen sulfide (H2S) content as specified in Condition 13.	Records Review	Intermittent	An excess emission was discovered on 10/19/2022 and was reported to ADEC on 10/21/2022 regarding an H2S exceedance of the natural gas burned in EU IDs 501, 503, 505, and 507 that began on 10/10/2022. The report was amended on 11/23/2022 to reflect that the H2S concentration was no longer being exceeded as of 10/27/2022. Both the original report and the amendment were attached to the 2H2022 FOR as well.
10.6	The Permittee shall either: a. obtain a semiannual statement from the fuel supplier of the fuel sulfur content in ppm; or b. analyze a representative sample of the fuel semiannually to determine the sulfur content using either ASTM D4084, D5504, D4810, D4913, D6228 or GPA Standard 2377, or a listed method approved in 18 AAC 50.035(b)-(c) and 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1).	Records Review	Continuous	None
10.7	The Permittee shall keep records of the sulfur content analysis required under Condition 10.6.a or 10.6.b.	Records Review	Continuous	None
10.8	The Permittee shall report as follows: a. Include copies of the records required by Condition 10.7 with the operating report required by Condition 71 for the period covered by the report. b. Report in accordance with Condition 70, whenever the fuel combusted causes sulfur compound emissions to exceed the standard of Condition 10.	Records Review	Continuous	None
Title I Permit Requirements				
Limits to Protect Ambient Air Quality Standards				
11	**Fuel Gas and Produced Gas Flaring Limits, EU ID 507.** Flare fuel gas and produced gas during routine or non-routine maintenance activities and other planned events. The Permittee shall flare fuel gas and produced gas quantities no greater than 152 MMscf of fuel gas and produced gas during any 12 consecutive-month period, at a rate of no greater than 20 MMscf per day.	Records Review	Continuous	None
11.1	Record the date and duration when fuel gas and produced gas flaring occurs and the quantity of fuel gas and produced gas flared.	Records Review	Continuous	None
11.2	Report in the operating report required by Condition 71, the date and duration of fuel gas and produced gas flaring and the total quantity of fuel gas and produced gas flared during the applicable reporting period; describe or document whether the flaring incident is considered an emergency operation, routine or non-routine maintenance operation, or other planned event.	Records Review	Continuous	None

Annual Compliance Certification
Permit No. AQ0417TVP03
Badami Development Facility
January 1-December 31, 2022

Condition Number	Condition Text	Method Used to Determine Compliance Status	Compliance Status	Permit Deviations Identified During Calendar Year
11.3	Report in accordance with Condition 70 if any of the limits in Condition 11 are exceeded.	Records Review	Continuous	None
12	**Air Quality Boundary.** Establish and maintain the ambient boundaries used in the ambient impact analysis using the following procedures:	Interview with Responsible Personnel	Continuous	None
12.1	Comply with the May 10, 2005 "CPF Pad Badami Unit – Public Access Control Plan" (Plan), or a subsequent written version approved by the Department that contains at least the following elements: a. a topographic map (or maps) that clearly shows the ambient boundaries, water bodies and Central Process Facility (CPF) pad; b. ambient boundaries that are consistent with the land owner's authorization to preclude public access from the area within the boundaries; c. defined methods of establishing and maintaining the boundary; and d. the date of the revised Public Access Control Plan.			
12.2	Do not revise the ambient air boundaries without Department approval. If requested by the Department, submit a revised ambient air impact analysis that demonstrates the emission activities will not cause or contribute to ambient air violations when using the proposed boundary.			
12.3	Submit all proposed revisions of the Public Access Control Plan, including the ambient boundary, to the Department's Juneau and Fairbanks Offices. Do not implement any change without written Department approval.			

Annual Compliance Certification
Permit No. AQ0417TVP03
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January 1-December 31, 2022

Condition Number	Condition Text	Method Used to Determine Compliance Status	Compliance Status	Permit Deviations Identified During Calendar Year
13	**Fuel Gas and Produced Gas Sulfur Limit.** Operate EU IDs 1, 8, 500, 501, 503, and 505 using fuel gas with a H2S content not to exceed 250 ppmv and operate EU ID 507 using fuel gas and produced gas with a H2S content not to exceed 250 ppmv.	Records Review	Intermittent	An excess emission was discovered on 10/19/2022 and was reported to ADEC on 10/21/2022 regarding an H2S exceedance of the natural gas burned in EU IDs 501, 503, 505, and 507 that began on 10/10/2022. The report was amended on 11/23/2022 to reflect that the H2S concentration was no longer being exceeded as of 10/27/2022. Both the original report and the amendment were attached to the 2H2022 FOR as well.
13.1	Monitor, record, and report in accordance with Conditions 10.6 through 10.8.	Records Review	Continuous	None
13.2	Report in accordance with Condition 70 if the fuel H2S content limit in Condition 13 is exceeded.	Records Review	Continuous	None
14	**Diesel Fuel Sulfur Limit.** Operate EU IDs 1, 8, 420a, and 421a using distillate fuel oil with a fuel sulfur content not to exceed 0.15 percent by weight (wt% S).	Records Review and Interview with Responsible Personnel	Continuous	None
14.1	Monitor, record, and report in accordance with Conditions 10.1 through 10.4.	Records Review	Continuous	None
14.2	Report in accordance with Condition 70 if the fuel sulfur content limit in Condition 14 is exceeded.	Records Review	Continuous	None
15	**Liquid Fuel Consumption Limit, EU IDs 420a and 421a.** For EU IDs 420a and 421a, the Permittee shall burn a combined total of no more than 800,000 gallons of liquid fuel during any 12 consecutive-month period.	Records Review	Continuous	None
15.1	Install and operate a dedicated fuel meter accurate to less than five percent error for EU ID 420a and 421a combined; and install and operate a dedicated continuous engine hour monitoring system for each unit.	Records Review and Interview with Responsible Personnel	Continuous	None
15.2	Monitor and record the monthly fuel consumption for EU IDs 420a and 421a combined, and the monthly hours of operation for each unit.	Records Review	Continuous	None
15.3	Except as provided in Condition 15.4, calculate and record the 12 consecutive month combined fuel consumption using fuel meter data.	Records Review	Continuous	None
15.4	If the fuel meter for EU IDs 420a and 421a is out of service, estimate the gallons of fuel consumed for the emission units using the hours of operation recorded in Condition 15.2, assuming the 100 percent load fuel consumption rate in gallons per hour for the unit for any period during which the unit was operating. The fuel consumption rate shall be the design fuel consumption of 97.8 gallons per hour.	Records Review and Interview with Responsible Personnel	Continuous	None
15.5	Report in the operating report required by Condition 71: a. the monthly and 12 consecutive month total fuel consumption for EU IDs 420a and 421a combined; and b. if the hours of operation were used to calculate the fuel use for any part of the 12 month rolling period as described in Condition 15.4, report the monthly and 12-consecutive month hours of operation for EU IDs 420a and 421a.	Records Review	Continuous	None

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15.6	Report in accordance with Condition 70 if the limit in Condition 15 is exceeded.	Records Review	Continuous	None
16	**Liquid Fuel Consumption Limits, EU IDs 1 and 8 (Drill Rig).** In all drill rig emissions units, EU IDs 1 and 8 listed in Table A, the Permittee shall burn a combined total of no more than 9,000 gallons of liquid fuel per day and 950,000 gallons of liquid fuel during any 12 consecutive-month period.	Records Review	Continuous	None
16.1	Monitor and record for each operational day, the quantity of fuel combusted in all drill rig emissions units, combined. Monitor fuel gas consumption using nonresettable fuel flow meters.	Records Review	Continuous	None
16.2	Calculate and record the daily combined, and 12 consecutive month combined, total fuel consumption in gallons. For units that fired with fuel gas, convert the quantity of fuel gas burned (in standard cubic feet (scf)) into a diesel gallon equivalent using the conversion factor of 115 scf of fuel gas to one gallon diesel fuel.	Records Review	Continuous	None
16.3	Report in the operating report required by Condition 71, the maximum daily fuel consumption and the 12 consecutive-month total fuel consumption for all drill rig emission units, combined, for each month of the reporting period.	Records Review	Continuous	None
16.4	Report as a permit deviation, in accordance with Condition 70 any time the fuel consumption exceeds a limit specified in Condition 16.	Records Review	Continuous	None
Best Available Control Technology (BACT) Limits				
17	**BACT Controls and Limits.** The Permittee shall install emission or operational controls as BACT for the following equipment:	Interview with Responsible Personnel	Continuous	None
17.1	NOx BACT for fuel burning equipment at Badami Development Facility is no post-combustion emission control with good operational practices. The Permittee shall:			
17.1 a)	Install and operate as BACT for the following fuel burning equipment at Badami Development Facility: (i) EU ID 420a and EU ID 421a with a modular common rail system (MCRS) as incorporated by the manufacturer; (ii) EU IDs 500 and 501 with dry low NOx combustion technology (SoLoNOx); (iii) EU ID 503 with low NOx burners/flue gas recirculation; and (iv) EU ID 505 with conventional burner technology.			
17.1 b)	Comply with the following NO_x emission limits: (i) EU IDs 500 and 501 shall not exceed 28.4 lb NOx/hr for operation under all conditions, and shall not exceed 85 ppmv corrected to 15 percent oxygen in SoLoNOx mode and at ambient temperatures above 0°F; (ii) EU ID 503 shall not exceed 0.095 lb NOx/MMBtu; and (iii) EU ID 505 shall not exceed 0.08 lb NOx/MMBtu.	Records Review	Continuous	None

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17.2	CO BACT for fuel burning equipment at Badami Development Facility is no post-combustion emission control with good operational practices. The Permittee shall: a. Comply with the following CO emission limits as representative of BACT: (i) EU IDs 500 and 501 shall not exceed 50 ppmv corrected to 15 percent oxygen when operating at 100 percent load in SoLoNOx mode at ambient temperatures above 0°F, 14 lb/hr when operating in SoLoNOx mode and at ambient temperatures above 0°F, and 385 lb/hr for operation under all other conditions; (ii) EU ID 503 shall not exceed 3.4 lb CO/hr; and (iii) EU ID 505 shall not exceed 0.15 lb CO/MMBtu. b. Limit CO emissions from EU IDs 500 and 501, combined, to no greater than 336 tons per 12 consecutive-month period.	Records Review and Interview with Responsible Personnel	Continuous	None
17.3	SO2 BACT for fuel burning equipment is use of low sulfur fuel with no post combustion controls. The Permittee shall: a. Comply with the following fuel sulfur limits as representative of BACT: (i) H2S content of fuel gas and produced gas fuel shall not exceed 250 ppmv; and (ii) Sulfur content of fuel oil shall not exceed 0.15 wt% S.	Records Review	Intermittent	An excess emission was discovered on 10/19/2022 and was reported to ADEC on 10/21/2022 regarding an H2S exceedance of the natural gas burned in EU IDs 501, 503, 505, and 507 that began on 10/10/2022. The report was amended on 11/23/2022 to reflect that the H2S concentration was no longer being exceeded as of 10/27/2022.
17.4	VOC BACT for fuel burning equipment and fuel storage tanks, and water treatment processes is no controls with good operation practices. BACT for water injection tanks and slop tank is a sealed system design. The flare BACT determination is smokeless tip design. No emission limits are imposed as representing BACT.	Interview with Responsible Personnel	Continuous	None
17.5	PM-10 BACT for fuel burning equipment is no controls with good operation practices. The Permittee shall: a. Comply with the following opacity limits as representative of BACT surrogate PM-10 emission limits:	Records Review	Continuous	None
17.5 a) i)	Visible emissions from EU IDs 420a and 421a shall not exceed 20 percent opacity averaged over any six consecutive minutes, except as described in Condition 17.5.a(ii); and			
17.5 a) ii)	If both oil and gas production cease for 30 consecutive days, EU IDs 420a and 421a shall not exceed 10 percent opacity averaged over any six consecutive minutes, until oil and gas production resumes.			
17.5 a) iii)	Visible emissions from EU IDs 500 and 501 shall not exceed 10 percent opacity averaged over any six consecutive minutes.	Interview with Responsible Personnel	Continuous	None
17.5 a) iv)	All other industrial processes, incinerators, and fuel burning equipment shall comply with the applicable State visible emission standards listed in Conditions 1 and 21.1	Interview with Responsible Personnel	Continuous	None
18	**BACT Monitoring, Recordkeeping, and Reporting.** The Permittee shall monitor, record, and reports as follows:	Records Review	Continuous	None
18.1	NOx and CO – To demonstrate compliance with the short-term NOx and CO BACT limits specified in Conditions 17.1.b and 17.2.a, the Permittee shall conduct source testing on EU IDs 500, 501, and 503, in accordance with Section 6 and as follows:			
18.1 a)	For EU IDs 500 and 501: (i) Conduct source tests during the summer months (April through September) and during winter months (October through March). (ii) During this permit term, the first summer test on EU IDs 500 and 501 shall be done within 12 months of the effective date of this permit and the second test (winter) during the life of this permit, except as follows: (A) If results of the previous winter source tests conducted in October 2014 shows that the winter test results are higher than the summer source test results conducted under this permit in all test runs at similar operating loads, the Permittee may elect to conduct source tests on EU IDs 500 or 501 once every five years during winter months only. (iii) For NOx, conduct source testing at the highest typical operating load of the unit. For units of the same make, model, and design, one unit within the group can be tested. The source test report shall provide NOx emissions (average of three valid one-hour-run results) in ppmv and in lb/hr for each unit tested. At the Permittee's discretion, the NOx BACT source test in this sub-condition may be conducted in conjunction with NSPS Subpart GG NOx source test required under Condition 32.2.a. (iv) For CO, conduct source testing at no less than four loads representative of the turbine's typical operating range. For units of the same make, model, and design, one unit within the group can be tested. The source test report shall provide CO emissions (average of three valid one-hour-test run results) in ppmv and in lb/hr for each unit tested.			
18.1 b)	For EU ID 503, conduct NOx and CO emission source tests as follows: (i) once within five years from the most recent source test conducted on the unit; (ii) at the highest typical operating load of the unit; and (iii) provide in the source test report NOx and CO emissions results in lb/MMBtu (average of three valid one-hour-run results).	Records Review	Continuous	None

<table>
<tr><th>Condition Number</th><th>Condition Text</th><th>Method Used to Determine Compliance Status</th><th>Compliance Status</th><th>Permit Deviations Identified During Calendar Year</th></tr>
<tr><td>18.2</td><td>CO – For EU IDs 500 and 501, monitor, record and report, as follows:</td><td rowspan="2">Records Review</td><td rowspan="2">Continuous</td><td rowspan="2">None</td></tr>
<tr><td>18.2 a)</td><td>Using the existing computer-based control system, monitor and record:
(i) operating time in hours (record time in minutes or decimal portions of an hour);
(ii) for each hour, the average percentage natural gas producer (% NGP) speed (use six-minute intervals to calculate the average % NGP speed for each hour of operation); and
(iii) for each hour, time in and out of SoLoNOx operation for each unit.
[10] For any time the computer based system is out of order, the Permittee shall estimate and record the hourly operating time, % NGP speed, and time in and out of SoLoNOx operation for each unit.</td></tr>
<tr><td>18.2 b)</td><td>Calculate and record the hourly CO emissions for EU IDs 500 and 501. Use the SoLoNOx mode and the hourly average percentage NGP speed (as determined in Condition 18.2.a(ii) to determine the appropriate CO emission factors listed in Table B or alternate CO emission factors approved in writing by the Department). Multiply the appropriate CO emission factor by the associated hours of operation to get hourly CO emissions.
Table B – EU ID 500 and 501 Turbine CO Emission Factors
<table>
<tr><th>Emissions unit ID(s)</th><th>SoLoNOx Mode</th><th>Gas Turbine Load Condition (% NGP speed average hourly value)</th><th>CO Emission Factor</th></tr>
<tr><td rowspan="6">500 & 501</td><td>In SoLoNOx Mode</td><td></td><td>4.7 lb/hr</td></tr>
<tr><td rowspan="5">Out of SoLoNOx Mode</td><td>% NGP ≥ 94</td><td>4.7 lb/hr</td></tr>
<tr><td>% NGP ≥ 90 and < 94</td><td>202.0 lb/hr</td></tr>
<tr><td>% NGP ≥ 87 and < 90</td><td>236.0 lb/hr</td></tr>
<tr><td>% NGP ≥ 84 and < 87</td><td>261.9 lb/hr</td></tr>
<tr><td>% NGP < 84</td><td>385 lb/hr</td></tr>
</table></td><td>Records Review</td><td>Continuous</td><td>None</td></tr>
<tr><td>18.2 c)</td><td>On calendar month basis, calculate and record the total monthly and 12 consecutive-month period CO emissions for EU IDs 500 and 501 individually, and EU ID 500 and 501 combined.</td><td>Records Review</td><td>Continuous</td><td>None</td></tr>
<tr><td>18.2 d)</td><td>Report in the operating report required by Condition 71, the monthly and 12 consecutive-month total CO emissions for EU IDs 500 and 501, each, and the combined total.</td><td>Records Review</td><td>Continuous</td><td>None</td></tr>
<tr><td>18.3</td><td>SO2 – Conduct fuel sulfur monitoring, recordkeeping and reporting in Conditions 10.1 through 10.8 to ensure compliance with SO2 BACT limits in Condition 17.3.</td><td>Records Review</td><td>Continuous</td><td>None</td></tr>
<tr><td>18.4</td><td>PM – Conduct visible emission monitoring as follows:
a. For EU IDs 420a and 421a, continue to conduct Method 9 visible emissions observations using monitoring, recordkeeping and reporting procedures detailed in Conditions 2 through 4. Indicate on the Visible Emissions Observation Form in Section 11 if the unit observed is subject to the 10 percent opacity limit as surrogate PM-10 BACT limit described in Condition 17.5.a(ii).
b. For EU IDs 500 and 501, comply with Condition 1.3.</td><td>Records Review</td><td>Continuous</td><td>None</td></tr>
<tr><td>18.5</td><td>Report in accordance with Condition 70 if any of the BACT limits under Condition 17 are exceeded.</td><td>Records Review</td><td>Continuous</td><td>None</td></tr>
<tr><td colspan="5">Restart Project</td></tr>
<tr><td>19</td><td>Limits on Use of Load Banks. Except as provided in Condition 20, after February 1, 2013, the Permittee shall not use load banks, water brakes, pump flow controls or other loads that have the single purpose to destroy energy in order to improve the CO emission performance of EU IDs 500 and 501. For purposes of this permit, a load bank is a resistance device that performs no process or space heating function.</td><td rowspan="3">Records Review and Interview with Responsible Personnel</td><td rowspan="3">Continuous</td><td rowspan="3">None</td></tr>
<tr><td>20</td><td>Load Bank Exception. The Permittee may use a load bank on a short term basis to address intermittent power fluctuations that may occur as a result of bringing on a second turbine for project ramp-up, with the plan of operating both turbines simultaneously. Monitor, record, and report, as follows:</td></tr>
<tr><td>20.1</td><td>Record each change in the load bank power use in kW in a written log, noting date, time, and “before” and “after” settings of load bank power use:
a. at each instance the load is adjusted; and
b. twice daily coincident with physical inspections of the load bank, whenever load bank is receiving power.</td></tr>
</table>

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20.2	Report in the operating report required by Condition 71: a. the number of hours the load bank was used; and b. a statement whether the load bank was used to address intermittent power fluctuations as a result of bringing on a second turbine for project ramp-up.	Records Review	Continuous	None
20.3	Report in accordance with Condition 70 if load banks were used for purposes other than to address intermittent power fluctuations, as a result of bringing on a second turbine for project ramp-up as specified in Condition 20.	Records Review	Continuous	None
Insignificant Emission Units				
21	For emissions units at the stationary source that are insignificant as defined in 18 AAC 50.326(d)-(i) that are not listed in this permit, the following apply:	Records Review	Continuous	None
21.1	**Visible Emissions Standard:** The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from an industrial process, fuel-burning equipment, or an incinerator to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.			
21.2	**PM Standard:** The Permittee shall not cause or allow PM emitted from an industrial process or fuel-burning equipment to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.	Records Review	Continuous	None
21.3	**Sulfur Standard:** The Permittee shall not cause or allow sulfur compound emissions, expressed as SO2, from an industrial process or fuel-burning equipment, to exceed 500 ppm averaged over three hours.	Records Review	Continuous	None
21.4	**General MR&R for Insignificant Emission Units** a. The Permittee shall submit the certification of compliance of Condition 72 based on reasonable inquiry; b. The Permittee shall comply with the requirements of Condition 53; c. The Permittee shall report in the operating report required by Condition 71 if an emission unit is insignificant because of actual emissions less than the thresholds of 18 AAC 50.326(e) and actual emissions become greater than any of those thresholds; and d. No other monitoring, recordkeeping or reporting is required.	Records Review	Continuous	None
Section 4 Federal Requirements Emission Units Subject to Federal NSPS Subpart A				
22	**NSPS Subpart A Notification.** For any affected facility or existing facility regulated under NSPS requirements in 40 C.F.R. 60, the Permittee shall furnish the Department and EPA written or electronic notification of:	Records Review	Continuous	None
22.1	the date that construction or reconstruction of an affected facility commences postmarked no later than 30 days after such date;			
22.2	the actual date of initial startup of an affected facility postmarked within 15 days after such date;			
22.3	any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies unless that change is specifically exempted under an applicable subpart or in 40 C.F.R. 60.14(e), postmarked 60 days or as soon as practicable before the change is commenced and shall include: a. information describing the precise nature of the change, b. present and proposed emission control systems, c. productive capacity of the facility before and after the change, and d. the expected completion date of the change;			
22.4	any proposed replacement of an existing facility, for which the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, postmarked as soon as practicable, but no less than 60 days before commencement of replacement, and including the following information: a. the name and address of owner or operator, b. the location of the existing facility, c. a brief description of the existing facility and the components that are to be replaced, d. a description of the existing and proposed air pollution control equipment, e. an estimate of the fixed capital cost of the replacements, and of constructing a comparable entirely new facility, f. the estimated life of the existing facility after the replacements, and g. a discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.			
23	**NSPS Subpart A Startup, Shutdown, & Malfunction Requirements.** The Permittee shall maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of EU IDs 500, 501, and 503, any malfunctions of associated air-pollution control equipment, or any periods during which a continuous monitoring system or monitoring device for EU IDs 500, 501, and 503 is inoperative.	Records Review	Continuous	None

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24	**NSPS Subpart A Excess Emissions and Monitoring Systems Performance Report.** The Permittee shall submit to the Department and to EPA a written "excess emissions and monitoring systems performance report " (EEMSP)' any time a limit in Conditions 32 and 33 has been exceeded as described in this condition. Submit the EEMSP reports with the summary report form as required in Condition 25. Written reports of excess emissions shall include the following information:	Records Review	Continuous	None
24.1	The magnitude of excess emissions, any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the process operating time during the reporting period.			
24.2	Identification of each period of excess emissions that occurred during startup, shutdown, and malfunction of EU IDs 500 and 501; the nature and cause of any malfunction, and the corrective action taken or preventative measures adopted.			
24.3	The date and time identifying each period during which a Continuous Monitoring System (CMS) was inoperative except for zero and span checks and the nature of any repairs or adjustments.			
24.4	A statement indicating whether or not any excess emissions occurred or the CMS was inoperative, repaired, or adjusted, at any time during the reporting period.			
25	**NSPS Subpart A Summary Report Form.** The Permittee shall submit to the Department and to EPA one "summary report form" in the format shown in Figure 1 of 40 C.F.R. 60.7 (see Attachment A) for each pollutant monitored for EU IDs 500 and 501. Except as provided in Condition 34.4.b, or when more frequent reporting is specifically required by an applicable subpart, case-by-case basis, or the EPA, the report shall be submitted semiannually, postmarked by the 30th day following the end of each 6-month period:	Records Review	Continuous	None
25.1	If the total duration of excess emissions for the reporting period is less than one percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than five percent of the total operating time for the reporting period, submit a summary report form unless the EEMSP report described in Condition 24 is requested, or			
25.2	If the total duration of excess emissions for the reporting period is one percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is five percent or greater of the total time for the reporting period, then submit a summary report form and the EEMSP described in Condition 24.			
26	**NSPS Subpart A Performance (Source) Tests.** The Permittee shall conduct source tests according to the applicable requirements of 40 C.F.R. 60.8 and Section 6 on any affected facility at such times as may be required by EPA, and shall provide the Department and EPA with a written report of the results of the source test.	N/A	Continuous	None
27	**NSPS Subpart A Good Air Pollution Control Practice.** At all times, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate EU IDs 500, 501, and 503 including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. The Administrator will determine whether acceptable operating and maintenance procedures are being used based on information available to the Administrator, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance records, and inspections of EU IDs 500, 501, and 503.	Records Review and Interview with Responsible Personnel	Continuous	None
28	**NSPS Subpart A Credible Evidence.** For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of the standards set forth in Conditions 31 and 33, nothing in 40 C.F.R. Part 60 shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether EU IDs 500 and 501 would have been in compliance with applicable requirements of 40 C.F.R. Part 60 if the appropriate performance or compliance test or procedure had been performed.	Records Review	Continuous	None
29	**NSPS Subpart A Concealment of Emissions.** The Permittee shall not build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of a standard set forth in Conditions 32, 33, and 36.1. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard that is based on the concentration of a pollutant in the gases discharged to the atmosphere.	Records Review and Interview with Responsible Personnel	Continuous	None
Steam Generating Units Subject to NSPS Subpart Dc, EU ID 503				
30	**NSPS Subpart Dc Fuel Consumption.** For EU ID 503 listed in Table A, the Permittee shall record the amount of each fuel combusted during each operating month and maintain the records for a period of two years following the date of such record; or monitor according to an EPA approved custom fuel-monitoring schedule. The Permittee shall determine fuel consumption in EU ID 503, as follows:	Records Review	Continuous	None
30.1	Unless otherwise approved, the Permittee shall maintain a record of the amount of fuel combusted on a quarterly basis for EU ID 503.	Records Review	Continuous	None
Turbines Subject to NSPS Subpart GG, EU IDs 500 and 501				
31	**NSPS Subpart GG NO_x Standard.** The Permittee shall not allow the exhaust gas concentration of NO_x to exceed 191 ppmvd at 15 percent O2, ISO, dry exhaust basis from each of EU IDs 500 and 501 listed in Table A.	Records Review	Continuous	None
32 & 32.1	**NO_x MR&R Requirements.** The Permittee shall monitor, record, and report compliance with the Subpart GG NOX standard in Condition 31, as follows: 32.1 **Emergency Fuel.** Stationary gas turbines with a heat input greater than or equal to 10.7 gigajoules per hour (10 million Btu/hour) when fired with natural gas are exempt from the standard in Condition 31 when being fired with an emergency fuel. Each period during which an exemption is in effect shall be included in the report required in Condition 24. For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported.	Records Review and Interview with Responsible Personnel	Continuous	None
32.2	**Monitoring.** The Permittee shall comply with the following:			
32.2 a)	**Periodic Testing.** For each turbine subject to Condition 31 that operates for 400 hours or more in any 12-month period during the life of this permit, the Permittee shall satisfy either Condition 32.2.a(i) or Condition 32.2.a(ii).			

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32.2 a) i)	For existing turbines whose latest emissions source testing was certified as operating at less than or equal to 90 percent of the limit shown in Condition 31, the Permittee shall conduct a NOx and O2 source test under 40 C.F.R. 60, Appendix A, Method 20, or Method 7E and either Method 3 or 3A within the first applicable criteria below: (A) Within 5 years of the latest performance test, or (B) Within 1 year of the effective date of this permit if the last source test occurred greater than five years prior to the effective date of this permit and the 400-hour threshold was triggered within 6 months of the permit issue date, or (C) Within 1 year after exceeding 400 hours of operation in a 12-month period if the last source test occurred greater than 4 years prior to the exceedance.	Records Review	Continuous	None
32.2 a) ii)	For existing turbines whose latest emissions source testing was certified as operating at greater than 90 percent of the limit shown in Condition 32, the Permittee shall conduct a NOx and O2 source test under 40 C.F.R. 60, Appendix A-7, Method 20, or Method 7E and either Method 3 or 3A, annually until two consecutive tests show performance results certified at less than or equal to 90 percent of the limit of Condition 31.			
32.2 b)	**Substituting Test Data.** The Permittee may use a Method 20, or Method 7E and either Method 3 or 3A test under Condition 32.2.a performed on only one of a group of similarly configured turbines to satisfy the requirements of those conditions for the other turbines in the group if:	Records Review	Continuous	None
32.2 b) i)	The Permittee demonstrates that test results are less than or equal to 90 percent of the applicable emission limits of Condition 31, and are projected under Condition 32.2.c to be less than or equal to 90 percent of the applicable limit at maximum load; and			
32.2 b) ii)	For any source test done after the effective date of this permit, the Permittee identifies in a source test plan under Condition 62: (A) the turbine to be tested; (B) the other turbines in the group that are to be represented by the test; and (C) why the turbine to be tested is representative, including that each turbine in the group (1) is located at a stationary source operated and maintained by the Permittee; (2) operates under close to identical ambient conditions as the untested turbines; (3) is the same make and model and has identical injectors and combustor; (4) uses the same fuel type from the same supply origin.			
32.2 b) iii)	The Permittee may not use substitute test results to represent emissions from a turbine or group of turbines if that turbine or group of turbines is operating at greater than 90 percent of the applicable emission limits of Condition 31.			
32.2 c)	**Load.** The Permittee shall comply with the following:	Records Review	Continuous	None
32.2 c) i)	Conduct all tests under Condition 32.2 in accordance with 40 C.F.R. 60.335(b)(2), except as otherwise approved in writing by the Department, or by EPA if the circumstances at the time of the EPA approval are still valid. For the highest load condition, if it is not possible to operate the turbine during the test at maximum load, the Permittee will test the turbine when operating at the highest load achievable by the turbine under the ambient and stationary source operating conditions in effect at the time of the test.			
32.2 c) ii)	Demonstrate in the source test plan for any test performed after the issue date of this permit whether the test is scheduled when maximum NOx emissions are expected.	Records Review	Continuous	None
32.2 c) iii)	If the highest operating rate tested is less than the maximum load of the tested turbine or another turbine represented by the test data,	Records Review	Continuous	None
32.2 c) iii) (A)	for each such turbine the Permittee shall provide to the Department as an attachment to the source test report (1) additional test information from the manufacturer or from previous testing of units in the group of turbines; if using previous testing of the group of turbines, the information must include all available test data for the turbines in the group, and (2) a demonstration based on the additional test information that projects the test results from Condition 32 to predict the highest load at which emissions will comply with the limit in Condition 31;			
32.2 c) iii) (B)	the Permittee shall not operate any turbine represented by the test data at loads for which the Permittee's demonstration predicts that emissions will exceed the emission limit of Condition 31;	Records Review	Continuous	None
32.2 c) iii) (C)	the Permittee shall comply with a written finding prepared by the Department that (1) the information is inadequate for the Department to reasonably conclude that compliance is assured at any load greater than the test load, and that the Permittee must not exceed the test load; (2) the highest load at which the information is adequate for the Department to reasonably conclude that compliance assured is less than maximum load, and the Permittee must not exceed the highest load at which compliance is predicted, or (3) the Permittee must retest during a period of greater expected demand on the turbine; and	Records Review	Continuous	None
32.2 c) iii) (D)	the Permittee may revise a load limit by submitting results of a more recent Method 20, or Method 7E and either Method 3 or 3A test done at a higher load, and, if necessary, the accompanying information and demonstration described in Condition 32.2.c(iii)(A); the new limit is subject to any new Department finding under Condition 32.2.c(iii)(C).	Records Review	Continuous	None
32.2 c) iv)	In order to perform a Method 20, or Method 7E and either Method 3 or 3A emission test, the Permittee may operate a turbine at a higher load than that prescribed by Condition 32.2.c(iii).	Records Review	Continuous	None
32.2 c) v)	For the purposes of Conditions 32.1 through 32.4, maximum load means the hourly average load that is the smallest of (A) 100 percent of manufacturer's design capacity of the gas turbine at ISO standard day conditions; (B) the highest load allowed by an enforceable condition that applies to the turbine; or (C) the highest load possible considering permanent physical restraints on the turbine or the equipment which it powers.	Records Review	Continuous	None
32.3	**Recordkeeping.** The Permittee shall keep records as follows:			

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32.3 a)	The Permittee shall comply with the following for each turbine for which a demonstration under Condition 32.2.c(iii) does not show compliance with the emission limit of Condition 32 at maximum load. (i) The Permittee shall keep records of (A) load; or (B) as approved by the Department, surrogate measurements for load and the method for calculating load from those measurements. (ii) Records in Condition 32.3.a shall be hourly or otherwise as approved by the Department. (iii) Within one month after submitting a demonstration under Condition 32.2.c(iii)(A)(2) that predicts that the highest load at which emissions will comply is less than maximum load, or within one month of a Department finding under Condition 32.2.c(iii)(C), whichever is earlier, the Permittee shall propose to the Department how they will measure load or load surrogates, and shall propose and comply with a schedule for installing any necessary equipment and beginning monitoring. The Permittee shall comply with any subsequent Department direction on the load monitoring methods, equipment, or schedule.	Records Review	Continuous	None
32.3 b)	For any turbine subject to Condition 32 that will operate less than 400 hours in any 12 consecutive months, the Permittee shall keep monthly records of the hours of operation.	Records Review	Continuous	None
32.4	**Reporting.** The Permittee shall report as follows:	Records Review	Continuous	None
32.4 a)	In each operating report under Condition 71, the Permittee shall list for each turbine tested or represented by testing at less than maximum load and for which the Permittee must limit load under Condition 32.2.c(iii) (i) the load limit; (ii) the turbine identification; and (iii) the highest load recorded under Condition 32.3.a during the period covered by the operating report.			
32.4 b)	In each operating report under Condition 71 for each turbine for which Condition 32.1 has not been satisfied because the turbine normally operates less than 400 hours in any 12 consecutive months, the Permittee shall identify (i) the turbine; (ii) the highest number of operating hours for any 12 consecutive months ending during the period covered by the report; and (iii) any turbine that operated for 400 or more hours.			
32.4 c)	The Permittee shall report under Condition 70 if (i) a test result exceeds the emission standard; (ii) Method 20, or Method 7E and either Method 3 or 3A testing is required under Condition 32.2.a(i) or 32.2.a(ii) but not performed, or (iii) the turbine was operated at a load exceeding that allowed by Conditions 32.2.c(iii)(B) and 32.2.c(iii)(C); exceeding a load limit is deemed a single violation rather than a multiple violation of both monitoring and the underlying emission limit.	Records Review	Continuous	None
33	**NSPS Subpart GG Sulfur Standard.** The Permittee shall not allow the sulfur content for the fuel burned in EU IDs 500 and 501 to exceed 0.8 percent by weight.	Records Review	Continuous	None
34	**SO2 MR&R Requirements.** The Permittee shall monitor, record, and report compliance with the Subpart GG SO2 standard in Condition 33, as follows:			
34.1	**Monitoring.** The Permittee shall monitor compliance with the standard listed in this condition as follows:			
34.1 a)	Monitor the total sulfur content of the fuel being fired in the turbine, except as provided in Conditions 33.1.b. The sulfur content of the fuel must be determined using total sulfur methods described in Condition 33.2.a. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4,000 ppmw), ASTM D4084–82, 94, D5504–01, D6228–98, or Gas Processors Association Standard 2377–86, which measure the major sulfur compounds may be used.			
34.1 b)	The owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in 40 C.F.R. 60.331(u), regardless of whether an existing custom schedule approved by the Administrator requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration: (i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or (ii) Representative fuel sampling data, which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in 40 C.F.R. 75, Appendix D, Section 2.3.1.4 or Section 2.3.2.4 is required.			
34.1 c)	For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the Permittee may, without submitting a special petition to the Administrator, continue monitoring on this schedule.	Records Review	Continuous	None
34.1 d)	The frequency of determining the sulfur content of the fuel shall be as follows: (i) Gaseous fuel. If the Permittee elects not to demonstrate sulfur content using options in Condition 33.1.b, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined under Condition 33.1.a and recorded once per unit operating day. (ii) Custom Schedules. Notwithstanding the requirements of Condition 33.1.d(i): (A) The Permittee may develop a custom schedule for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply, according to the provisions and as allowed under 40 C.F.R. 60.334(i)(3). The two custom sulfur monitoring schedules set forth in 40 C.F.R. 60.334(i)(3)(i)(A) through (D) and 60.334(i)(3)(ii) are acceptable without prior Administrative approval. (B) Alternatively, as provided under Condition 33.1c, the Permittee may continue to use the Alternative Monitoring Plan approved by EPA on 11/12/98. The EPA-approved AMP (11/12/98) requires quarterly monitoring for six calendar quarters, then reduces monitoring to semiannually if H2S results are below 80 ppm.	Records Review	Continuous	None
34.2	**Test Methods and Procedures.** If the Permittee periodically determines the sulfur content of the fuel combusted in the turbine under Condition 33.1.d(ii) a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:	Records Review	Continuous	None

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34.2 a)	For gaseous fuels, ASTM D1072-80, 90; D3246-81, 92, 96; D4468-85; or D6667-01. The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.	Records Review	Continuous	None
34.2 b)	The fuel analyses required under Condition 34.2 may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.	Records Review	Continuous	None
34.3	**Recordkeeping**. The Permittee shall keep records as required by Condition 66 and the EPA-approved AMP (11/12/98) as follows: a. Maintain records of all sulfur monitoring data. b. Maintain a record documenting the source of fuel gas. A substantial change in fuel gas quality shall be considered a change in fuel supply. c. Maintain records of all turbine operation on all fuels other than fuel gas. d. Maintain records on-site for a period of five years from the generation of such record.	Records Review	Continuous	None
34.4	**Reporting.** The Permittee shall report as follows: a. For each affected unit that periodically determines the fuel sulfur content under Condition 33.1, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with 40 C.F.R. 60.7(c) as summarized in Condition 25 except where otherwise approved by a custom fuel monitoring schedule. Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction as described by 40 C.F.R. 60.334(j)(2). b. As required by the EPA-approved AMP (11/12/98), submit to EPA within 60 days of any changes in supplier or source of fuel, or use of any fuel other than fuel gas. c. As required by the EPA-approved AMP (11/12/98), annually report the results of all sulfur monitoring to EPA. Provide a copy of the report to the Department by February 1 following the end of each calendar year.	Records Review	Continuous	None
Compression Ignition (CI) Internal Combustion Engine (ICE) Subject to NSPS Subpart IIII, EU IDs 420a and 421a				
35	**NSPS Subpart IIII Applicability and General Compliance Requirements.** For EU IDs 420a and 421a listed in Table A, the Permittee shall comply with the applicable requirements for a non-emergency stationary compression ignition (CI) internal combustion engine (ICE) whose construction, modification, or reconstruction commences after July 11, 2005 where the stationary CI ICE is manufactured after April 1, 2006.	Records Review and Interview with Responsible Personnel	Continuous	None
35.1	Operate and maintain the stationary CI ICE and control device according to the manufacturer's written instructions or procedures developed by the Permittee that are approved by the engine manufacturer over the entire life of the engine. In addition, the Permittee may only change those settings that are permitted by the manufacturer.			
35.2	Comply with the applicable provisions of Subpart A as specified in Table 8 to Subpart IIII.			
36	**NSPS Subpart IIII Emission Standards.** For EU ID 420a and 421a, the Permittee shall comply with the following emission standards:	Records Review	Continuous	None
36.1	Exhaust emission from EU IDs 420a and 421a shall not exceed the following applicable exhaust emission standards for new nonroad CI engines in 40 C.F.R. 89.112 and 89.113 for all pollutants, for the same displacement and maximum engine power (i.e., Tier 2 emission factors): a. 6.4 g/kW-hr for NMHC + NOx; b. 3.5 g/KW-hr for CO; c. 0.20 g/kW-hr for PM; and d. Exhaust opacity from EU IDs 420a and 421a must not exceed: (i) 20 percent during the acceleration mode; (ii) 15 percent during the lugging mode; and (iii) 50 percent during the peaks in either the acceleration or lugging modes.			
37	**NSPS Subpart IIII Monitoring and Recordkeeping.** For EU IDs 420a and 421a, the Permittee shall comply with the following:	Records Review and Interview with Responsible Personnel	Continuous	None
37.1	Demonstrate compliance with the emission standards by purchasing an engine certified to the applicable emission standards in Condition 36.1. The engine must be installed and configured according to the manufacturer's specifications, except as permitted in Condition 37.2.			
37.2	If the Permittee does not install, configure, operate, and maintain EU IDs 420a and 421a and control device according to the manufacturer's emission-related written instructions, or changes emission-related settings in a way that is not permitted by the manufacturer, the Permittee shall demonstrate compliance in accordance with 40 C.F.R. 60.4211(g)(3).			
38	**NSPS Subpart IIII Reporting.** For EU IDs 420a and 421a, the Permittee shall report in accordance with Condition 70 in the event of excess emissions or deviation from any of the requirements of Conditions 35 through 37.	Records Review	Continuous	None
General Federal Requirements				
39	**Asbestos NESHAP.** The Permittee shall comply with the requirements set forth in 40 C.F.R. 61.145 and 61.150 of Subpart M, and the applicable sections set forth in 40 C.F.R. 61, Subpart A and Appendix A.	Interview with Responsible Personnel	Continuous	None
40	Protection of Stratospheric Ozone, 40 C.F.R. 82.	Interview with Responsible Personnel	Continuous	None
40.1	**Subpart F – Recycling and Emissions Reduction** The Permittee shall comply with the standards for recycling and emission of refrigerants set forth in 40 C.F.R. 82, Subpart F.			
40.2	**Subpart G – Significant New Alternatives Policy (Halon)** The Permittee shall comply with the applicable prohibitions set out in 40 C.F.R. 82.174(b) – (d) (Protection of Stratospheric Ozone Subpart G – Significant New Alternatives Policy Program).			
40.3	**Subpart H – Halon Emission Reduction** The Permittee shall comply with the applicable prohibitions set out in 40 C.F.R. 82.270(b) – (f) (Protection of Stratospheric Ozone Subpart H – Halon Emission Reduction).			

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NESHAPs Applicability Determinations				
41	The Permittee shall determine rule applicability and designation of affected sources under National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Source Categories (40 C.F.R. 63) in accordance with the procedures described in 40 C.F.R. 63.1(b).	Interview with Responsible Personnel	Continuous	None
41.1	If an owner or operator of a stationary source who is in the relevant source category determines that the source is not subject to a relevant standard or other requirement established under 40 C.F.R. 63, the owner or operator must keep a record as specified in §63.10(b)(3).			
41.2	If a source becomes affected by an applicable subpart of 40 C.F.R. 63, the owner or operator shall comply with such standard by the compliance date established by the Administrator in the applicable subpart, in accordance with 40 C.F.R. 63.6(c).			
41.3	After the effective date of any relevant standard promulgated by the Administrator under this part, an owner or operator who constructs a new affected source that is not major-emitting or reconstructs an affected source that is not major-emitting that is subject to such standard, or reconstructs a source such that the source becomes an affected source subject to the standard, must notify the Administrator and the Department of the intended construction or reconstruction. The notification must be submitted in accordance with the procedures in 40 C.F.R. 63.9(b).			
42	**NSPS and NESHAP Reports.** The Permittee shall:	Records Review	Continuous	None
42.1	**Reports:** Except for federal reports and notices submitted through EPA's Central Data Exchange (CDX) and Compliance and Emissions Data Reporting Interface (CEDRI) online reporting system, attach to the operating report required by Condition 71 for the period covered by the report, a copy of any NSPS and NESHAPs reports submitted to the U.S. Environmental Protection Agency (EPA) Region 10. For reports submitted through CDX/CEDRI, state in the operating report the date and a brief description of each of the online reports submitted during the reporting period; and			
42.2	**Waivers:** Upon request by the Department, provide a written copy of any EPA granted alternative monitoring requirement, custom monitoring schedule or waiver of the Federal emission standards, recordkeeping, monitoring, performance testing, or reporting requirements. The Permittee shall keep a copy of each U.S. EPA issued monitoring waiver or custom monitoring schedule with the permit.	Records Review	Continuous	None
Section 5 General Conditions Standard Terms and Conditions				
43	Each permit term and condition is independent of the permit as a whole and remains valid regardless of a challenge to any other part of the permit.	Interview with Responsible Personnel	Continuous	None
44	The permit may be modified, reopened, revoked and reissued, or terminated for cause. A request by the Permittee for modification, revocation and re-issuance, or termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition.	Interview with Responsible Personnel	Continuous	None
45	The permit does not convey any property rights of any sort, nor any exclusive privilege.	Interview with Responsible Personnel	Continuous	None
46	**Administration Fees.** The Permittee shall pay to the Department all assessed permit administration fees. Administration fee rates are set out in 18 AAC 50.400-403.	Records Review	Continuous	None
47	**Assessable Emissions.** The Permittee shall pay to the Department an annual emission fee based on the stationary source's assessable emissions as determined by the Department under 18 AAC 50.410. The Department will assess fees per ton of each air pollutant that the stationary source emits or has the potential to emit in quantities greater than 10 tons per year. The quantity for which fees will be assessed is the lesser of	Records Review	Continuous	None
47.1	the stationary source's assessable potential to emit of 931 TPY; or			
47.2	the stationary source's projected annual rate of emissions that will occur from July 1 to the following June 30, based upon credible evidence of actual annual emissions emitted during the most recent calendar year or another 12-month period approved in writing by the Department, when demonstrated by the most representative of one or more of the following methods: a. an enforceable test method described in 18 AAC 50.220; b. material balance calculations; c. emission factors from EPA's publication AP-42, Vol. I, adopted by reference in 18 AAC 50.035; or d. other methods and calculations approved by the Department including appropriate vendor-provided emissions factors when sufficient documentation is provided.	Records Review	Continuous	None
48	**Assessable Emission Estimates.** Emission fees will be assessed as follows:	Records Review	Continuous	None
48.1	no later than March 31 of each year, the Permittee may submit an estimate of the stationary source's assessable emissions to ADEC, Air Permits Program, ATTN: Assessable Emissions Estimate, 410 Willoughby Ave., Suite 303, PO Box 111800, Juneau, AK 99811-1800; the submittal must include all of the assumptions and calculations used to estimate the assessable emissions in sufficient detail so the Department can verify the estimates; or			
48.2	if no estimate is submitted on or before March 31 of each year, emission fees for the next fiscal year will be based on the potential to emit set forth in Condition 47.1.			
49	**Good Air Pollution Control Practice.** The Permittee shall do the following for EU IDs 505 and 507:	Records Review	Continuous	None
49.1	perform regular maintenance considering the manufacturer's or the operator's maintenance procedures;			
49.2	keep records of any maintenance that would have a significant effect on emissions; the records may be kept in electronic format; and			
49.3	keep a copy of either the manufacturer's or the operator's maintenance procedures.			
50	**Dilution.** The Permittee shall not dilute emissions with air to comply with this permit. Monitoring shall consist of an annual certification that the Permittee does not dilute emissions to comply with this permit.	Interview with Responsible Personnel	Continuous	None
51	**Reasonable Precautions to Prevent Fugitive Dust.** A person who causes or permits bulk materials to be handled, transported, or stored, or who engages in an industrial activity or construction project shall take reasonable precautions to prevent particulate matter from being emitted into the ambient air.	Interview with Responsible Personnel	Continuous	None
52	**Stack Injection.** The Permittee shall not release materials other than process emissions, products of combustion, or materials introduced to control pollutant emissions from a stack at a source constructed or modified after November 1, 1982, except as authorized by a construction permit, Title V permit, or air quality control permit issued before October 1, 2004.	Records Review and Interview with Responsible Personnel	Continuous	None
53	**Air Pollution Prohibited.** No person may permit any emission which is injurious to human health or welfare, animal or plant life, or property, or which would unreasonably interfere with the enjoyment of life or property.	Records Review and Interview with Responsible Personnel	Continuous	None

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53.1	**Monitoring, Recordkeeping, and Reporting for Condition 53:**	Records Review	Continuous	None
53.1a	If emissions present a potential threat to human health or safety, the Permittee shall report any such emissions according to Condition 70.			
53.1b	As soon as practicable after becoming aware of a complaint that is attributable to emissions from the stationary source, the Permittee shall investigate the complaint to identify emissions that the Permittee believes have caused or are causing a violation of Condition 53.			
53.1c	The Permittee shall initiate and complete corrective action necessary to eliminate any violation identified by a complaint or investigation as soon as practicable if (i) after an investigation because of a complaint or other reason, the Permittee believes that emissions from the stationary source have caused or are causing a violation of Condition 53; or (ii) the Department notifies the Permittee that it has found a violation of Condition 53.	Records Review and Interview with Responsible Personnel	Continuous	None
53.1d	The Permittee shall keep records of (i) the date, time, and nature of all emissions complaints received; (ii) the name of the person or persons that complained, if known; (iii) a summary of any investigation, including reasons the Permittee does or does not believe the emissions have caused a violation of Condition 53; and (iv) any corrective actions taken or planned for complaints attributable to emissions from the stationary source.	Records Review	Continuous	None
53.1e	With each stationary source operating report under Condition 71, the Permittee shall include a brief summary report which must include a. the number of complaints received; b. the number of times the Permittee or the Department found corrective action necessary; c. the number of times action was taken on a complaint within 24 hours; and d. the status of corrective actions the Permittee or Department found necessary that were not taken within 24 hours.	Records Review	Continuous	None
53.1f	The Permittee shall notify the Department of a complaint that is attributable to emissions from the stationary source within 24 hours after receiving the complaint, unless the Permittee has initiated corrective action within 24 hours of receiving the complaint.	Records Review	Continuous	None
54, 54.1, & 54.2	**Technology-Based Emission Standard.** If an unavoidable emergency, malfunction (as defined in 18 AAC 50.235(d)), or non-routine repair (as defined in 18 AAC 50.990(64), causes emissions in excess of a technology based emission standard22 listed in Conditions 17, 31, 33, 36, and 40.1 (refrigerants), the Permittee shall	Interview with Responsible Personnel	Continuous	None
54.1	take all reasonable steps to minimize levels of emissions that exceed the standard; and	Interview with Responsible Personnel	Continuous	None
54.2	report in accordance with Condition 70; the report must include information on the steps taken to mitigate emissions and corrective measures taken or to be taken.	Records Review	Intermittent	An excess emission was discovered on 10/19/2022 and was reported to ADEC on 10/21/2022 regarding an H2S exceedance of the natural gas burned in EU IDs 501, 503, 505, and 507 that began on 10/10/2022. The report was amended on 11/23/2022 to reflect that the H2S concentration was no longer being exceeded as of 10/27/2022.
Open Burning Requirements				
55	**Open Burning.** If the Permittee conducts open burning at this stationary source, the Permittee shall comply with the requirements of 18 AAC 50.065. The Permittee shall:	Records Review	Continuous	None
55.1	keep written records to demonstrate that the Permittee complies with the limitations in this condition and the requirements of 18 AAC 50.065. Upon request by the Department, submit copies of the records; and			
55.2	include this condition in the annual certification required under Condition 72.			
Section 6 General Source Testing and Monitoring Requirements				
56	**Requested Source Tests.** In addition to any source testing explicitly required by the permit, the Permittee shall conduct source testing as requested by the Department to determine compliance with applicable permit requirements.	N/A	Continuous	None
57	**Operating Conditions.** Unless otherwise specified by an applicable requirement or test method, the Permittee shall conduct source testing	N/A	Continuous	None
57.1	at a point or points that characterize the actual discharge into the ambient air; and		Continuous	None
57.2	at the maximum rated burning or operating capacity of the emissions unit or another rate determined by the Department to characterize the actual discharge into the ambient air.		Continuous	None

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58	**Reference Test Methods.** The Permittee shall use the following test methods when conducting source testing for compliance with this permit:	N/A	Continuous	None
58.1	Source testing for compliance with requirements adopted by reference in 18 AAC 50.040(a) must be conducted in accordance with the methods and procedures specified in 40 C.F.R. 60.		Continuous	None
58.2	Source testing for compliance with requirements adopted by reference in 18 AAC 50.040(c) must be conducted in accordance with the source test methods and procedures specified in 40 C.F.R. 63.		Continuous	None
58.3	Source testing for the reduction in visibility through the exhaust effluent must be conducted in accordance with the procedures set out in Reference Method 9. The Permittee may use the form in Section 11 to record data.		Continuous	None
58.4	Source testing for emissions of total particulate matter, sulfur compounds, nitrogen compounds, carbon monoxide, lead, volatile organic compounds, fluorides, sulfuric acid mist, municipal waste combustor organics, metals, and acid gases must be conducted in accordance with the methods and procedures specified in 40 C.F.R. 60, Appendix A.		Continuous	None
58.5	Source testing for emissions of PM-10 must be conducted in accordance with the procedures specified in 40 C.F.R. 51, Appendix M, Methods 201 or 201A and 202.		Continuous	None
58.6	Source testing for emissions of any pollutant may be determined using an alternative method approved by the Department in accordance with 40 C.F.R. 63 Appendix A, Method 301.		Continuous	None
59	**Excess Air Requirements.** To determine compliance with this permit, standard exhaust gas volumes must include only the volume of gases formed from the theoretical combustion of the fuel, plus the excess air volume normal for the specific emission unit type, corrected to standard conditions (dry gas at 68° F and an absolute pressure of 760 millimeters of mercury).	N/A	Continuous	None
60	**Test Exemption.** The Permittee is not required to comply with Conditions 62, 63 and 64 when the exhaust is observed for visible emissions by Method 9 Plan (Condition 2.3).	N/A	Continuous	None
61	**Test Deadline Extension.** The Permittee may request an extension to a source test deadline established by the Department. The Permittee may delay a source test beyond the original deadline only if the extension is approved in writing by the Department's appropriate division director or designee.	N/A	Continuous	None
62	**Test Plans.** Except as provided in Condition 60, before conducting any source tests, the Permittee shall submit a plan to the Department. The plan must include the methods and procedures to be used for sampling, testing, and quality assurance and must specify how the emission unit will operate during the test and how the Permittee will document that operation. The Permittee shall submit a complete plan within 60 days after receiving a request under Condition 56 and at least 30 days before the scheduled date of any test unless the Department agrees in writing to some other time period. Retesting may be performed without resubmitting the plan.	N/A	Continuous	None
63	**Test Notification.** Except as provided in Condition 60, at least 10 days before conducting a source test, the Permittee shall give the Department written notice of the date and the time the source test will begin.	Records Review	Continuous	None
64	**Test Reports.** Except as provided in Condition 60, within 60 days after completing a source test, the Permittee shall submit two copies of the results in the format set out in the Source Test Report Outline, adopted by reference in 18 AAC 50.030. The Permittee shall additionally certify the results in the manner set out in Condition 67. If requested in writing by the Department, the Permittee must provide preliminary results in a shorter period of time specified by the Department.	Records Review	Continuous	None
65	**Particulate Matter Calculations.** In source testing for compliance with the PM standards in Conditions 6 and 22.2, the three-hour average is determined using the average of three one-hour test runs.	Records Review	Continuous	None
Section 7. General Recordkeeping and Reporting Requirements				
66	**Recordkeeping Requirements.** The Permittee shall keep all records required by this permit for at least five years after the date of collection, including:	Records Review	Continuous	None
66.1	Copies of all reports and certifications submitted pursuant to this section of the permit; and			
66.2	Records of all monitoring required by this permit, and information about the monitoring including: a. the date, place, and time of sampling or measurements; b. the date(s) analyses were performed; c. the company or entity that performed the analyses; d. the analytical techniques or methods used; e. the results of such analyses; and, f. the operating conditions as existing at the time of sampling or measurement.			
Reporting Requirements				
67	**Certification.** The Permittee shall certify any permit application, report, affirmation, or compliance certification submitted to the Department and required under the permit by including the signature of a responsible official for the permitted stationary source following the statement: "Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete." Excess emission reports must be certified either upon submittal or with an operating report required for the same reporting period. All other reports and other documents must be certified upon submittal.	Records Review	Continuous	None
67.1	The Department may accept an electronic signature on an electronic application or other electronic record required by the Department if a. a certifying authority registered under AS 09.80.020 verifies that the electronic signature is authentic; and b. the person providing the electronic signature has made an agreement, with the certifying authority described in Condition 67.1.a, that the person accepts or agrees to be bound by an electronic record executed or adopted with that signature.	Records Review	Continuous	None

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68	**Submittals.** Unless otherwise directed by the Department or this permit, the Permittee shall submit one certified copy of reports, compliance certifications, and/or other submittals required by this permit to ADEC, Air Permits Program, 610 University Ave., Fairbanks, AK 99709-3643, ATTN: Compliance Technician. The Permittee may submit the documents electronically or by hard copy.	Records Review	Continuous	None
68.1	Provide electronic submittals, either by: a. E-mail using dec.aq.airreports@alaska.gov; or b. using the Department's Air Online Services at http://dec.alaska.gov/applications/air/airtoolsweb/.			
69	**Information Requests.** The Permittee shall furnish to the Department, within a reasonable time, any information the Department requests in writing to determine whether cause exists to modify, revoke and reissue, or terminate the permit or to determine compliance with the permit. Upon request, the Permittee shall furnish to the Department copies of records required to be kept by the permit. The Department may require the Permittee to furnish copies of those records directly to the Federal Administrator.	Records Review	Continuous	None
70	**Excess Emissions and Permit Deviation Reports.**	Records Review	Continuous	None
70.1	Except as provided in Condition 53, the Permittee shall report all emissions or operations that exceed or deviate from the requirements of this permit as follows: a. In accordance with 18 AAC 50.240(c), as soon as possible after the event commences or is discovered, report (i) emissions that present a potential threat to human health or safety; and (ii) excess emissions that the Permittee believes to be unavoidable; b. In accordance with 18 AAC 50.235(a), within two working days after the event commenced or was discovered, report an unavoidable emergency, malfunction, or nonroutine repair that causes emissions in excess of a technology based emission standard; and c. Report all other excess emissions and permit deviations (i) within 30 days of the end of the month during which the excess emissions or deviation occurred, except as provided in Conditions 70.1.c(ii) and 70.1.c(iii); or (ii) if a continuous or recurring excess emissions is not corrected within 48 hours of discovery, within 72 hours of discovery unless the Department provides written permission to report under Condition 70.1.c(i); and (iii) for failure to monitor, as required in other applicable conditions of this permit.	Records Review	Intermittent	None
70.2	When reporting either excess emissions or permit deviations, the Permittee shall report using either the Department's online form, which can be found at http://dec.alaska.gov/applications/air/airtoolsweb, or if the Permittee prefers, the form contained in Section 12 of this permit. The Permittee must provide all information called for by the form that is used.	Records Review	Continuous	None
70.3	If requested by the Department, the Permittee shall provide a more detailed written report as requested to follow up on an excess emissions report.	Records Review	Continuous	None
71	**Operating Reports.** During the life of this permit, the Permittee shall submit to the Department an original and one copy of an operating report by August 1 for the period January 1 to June 30 of the current year and by February 1 for the period July 1 to December 31 of the previous year.	Records Review	Continuous	None
71.1	The operating report must include all information required to be in operating reports by other conditions of this permit.	Records Review	Continuous	None
71.2	If excess emissions or permit deviations that occurred during the reporting period are not reported under Condition 71.1, the Permittee shall identify a. the date of the deviation; b. the equipment involved; c. the permit condition affected; d. a description of the excess emissions or permit deviation; and e. any corrective action or preventive measures taken and the date of such actions; or	Records Review	Continuous	None
71.3	When excess emissions or permit deviations have already been reported under Condition 70 the Permittee shall cite the date or dates of those reports.	Records Review	Continuous	None
71.4	The operating report shall include a listing of emissions monitored under Conditions 2.3.e and 32.2.a(ii) which trigger additional testing or monitoring, whether or not the emissions monitored exceed an emission standard. The Permittee shall include in the report. a. the date of the emissions; b. the equipment involved; c. the permit condition affected; and d. the monitoring result which triggered the additional monitoring.	Records Review	Continuous	None
71.5	Transition from expired to renewed permit. For the first period of this renewed operating permit, also provide the previous permit's operating report elements covering that partial period immediately preceding the effective date of this renewed permit.	Records Review	Continuous	None

Annual Compliance Certification
Permit No. AQ0417TVP03
Badami Development Facility
January 1-December 31, 2022

Condition Number	Condition Text	Method Used to Determine Compliance Status	Compliance Status	Permit Deviations Identified During Calendar Year
72	**Annual Compliance Certification.** Each year by March 31, the Permittee shall compile and submit to the Department an original and one copy of an annual compliance certification report[23]. [23] See Condition 72.2 for clarification on the number of reports required.	Records Review	Continuous	None
72.1	Certify the compliance status of the stationary source over the preceding calendar year consistent with the monitoring required by this permit, as follows: a. identify each term or condition set forth in Section 3 through Section 9, that is the basis of the certification; b. briefly describe each method used to determine the compliance status; c. state whether compliance is intermittent or continuous; and			
72.2	**Transition from expired to renewed permit.** For the first period of this renewed operating permit, also provide the previous permit's annual compliance certification report elements covering that partial period immediately preceding the effective date of this renewed permit.	Records Review	Continuous	None
72.3	In addition, submit a copy of the report directly to the EPA-Region 10, Office of Air Quality, M/S OAQ-107, 1200 Sixth Avenue, Seattle, WA 98101.	Records Review	Continuous	None
73	**Emission Inventory Reporting.** The Permittee shall submit to the Department reports of actual emissions, by emission unit, of CO, NH3, NOx, PM10, PM2.5, SO2, VOCs and Lead (Pb) (and lead compounds) using the form in Section 13 of this permit, as follows:			
73.1	Every third year by March 31 since the stationary source's potential to emit emissions for the previous calendar year exceeds 100 TPY of NOx.			
73.2	The Permittee shall commence reporting in 2015 for the calendar year 2014, 2018 for calendar year 2017, etc.	Records Review	Continuous	None
73.3	Include in the report required by this condition, the required data elements contained within the form in Section 13 or those contained in Table 2A of Appendix A to Subpart A of 40 C.F.R. 51 (final rule published in 73 FR 76556 (December 17, 2008)) for each stack associated with an emission unit.			
Section 8. Permit Changes and Renewal				
74	**Permit Applications and Submittals.** The Permittee shall comply with the following requirements for submitting application information to the EPA Region 10:			
74.1	The Permittee shall provide a copy of each application for modification or renewal of this permit, including any compliance plan, or application addenda, at the time the application or addendum is submitted to the Department;			
74.2	The information shall be submitted to the same address as in Condition 72.3.	Records Review	Continuous	None
74.3	To the extent practicable, the Permittee shall provide to EPA applications in portable document format (PDF); MS Word format (.doc); or other computer-readable format compatible with EPA's national database management system; and			
74.4	The Permittee shall maintain records as necessary to demonstrate compliance with this condition.			
75	**Emissions Trading.** 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 the permit.	N/A	Continuous	None
76	**Off Permit Changes.** The Permittee may make changes that are not addressed or prohibited by this permit other than those subject to the requirements of 40 C.F.R. Part 72 through 78 or those that are modifications under any provision of Title I of the Act to be made without a permit revision, provided that the following requirements are met:			
76.1	Each such change shall meet all applicable requirements and shall not violate any existing permit term or condition;	Records Review	Continuous	None
76.2	Provide contemporaneous written notice to EPA and the Department of each such change, except for changes that qualify as insignificant under 18 AAC 50.326(d) – (i). Such written notice shall describe each such change, including the date, any change in emissions, pollutants emitted, and any applicable requirement that would apply as a result of the change;			
76.3	The change shall not qualify for the shield under 40 C.F.R. 71.6(f);	Records Review	Continuous	None
76.4	The Permittee shall keep a record describing changes made at the stationary source that result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from those changes.	Interview with Responsible Personnel	Continuous	None
77	**Operational Flexibility.** The Permittee may make changes within the permitted stationary source without requiring a permit revision if the changes are not modifications under any provision of Title I of the Act and 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):			
77.1	The Permittee shall provide EPA and the Department with a written notification no less than seven days in advance of the proposed change.	Records Review	Continuous	None
77.2	For each such change, the notification required by Condition 77.1 shall include a brief description of the change within the permitted stationary source, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change.			
77.3	The permit shield described in 40 C.F.R. 71.6(f) shall not apply to any change made pursuant to Condition 77.			
78	**Permit Renewal.** To renew this permit, the Permittee shall submit to the Department25 an application under 18 AAC 50.326 no sooner than March 13, 2022 and no later than March 13, 2023. The renewal application shall be complete before the permit expiration date listed on the cover page of this permit. Permit expiration terminates the stationary source's right to operate unless a timely and complete renewal application has been submitted consistent with 40 C.F.R. 71.7(b) and 71.5(a)(1)(iii).	Records Review	Continuous	None
Section 9 Compliance Requirements				
General Compliance Requirements				
79	Compliance with permit terms and conditions is considered to be compliance with those requirements that are			
79.1	included and specifically identified in the permit; or	Records Review	Continuous	No Compliance Task
79.2	determined in writing in the permit to be inapplicable.			

Annual Compliance Certification
Permit No. AQ0417TVP03
Badami Development Facility
January 1-December 31, 2022

Condition Number	Condition Text	Method Used to Determine Compliance Status	Compliance Status	Permit Deviations Identified During Calendar Year
80	The Permittee must comply with each permit term and condition. Noncompliance with a permit term or condition constitutes a violation of AS 46.14, 18 AAC 50, and, except for those terms or conditions designated in the permit as not federally enforceable, the Clean Air Act, and is grounds for	Records Review	Intermittent	A permit deviation was discovered on 7/16/2022 and reported on 7/28/2022 regarding the failure to increase reporting of the H2S concentration from semi-annually to quarterly beginning with the 1H2019 FOR per the EPA Approved Alternate Monitoring Plan dated 11/12/1998. An excess emission was discovered on 10/19/2022 and was reported to ADEC on 10/21/2022 regarding an H2S exceedance of the natural gas burned in EU IDs 501, 503, 505, and 507 that began on 10/10/2022.
80.1	an enforcement action;	N/A	Continuous	No Compliance Task
80.2	permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280; or			
80.3	denial of an operating permit renewal application.			
81	It is not a defense in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with a permit term or condition.	Records Review	Continuous	None
82	The Permittee shall allow the Department or an inspector authorized by the Department, upon presentation of credentials and at reasonable times with the consent of the owner or operator to	Interview with Responsible Personnel	Continuous	None
82.1	enter upon the premises where a source subject to the permit is located or where records required by the permit are kept;			
82.2	have access to and copy any records required by the permit;			
82.3	inspect any stationary source, equipment, practices, or operations regulated by or referenced in the permit; and			
82.4	sample or monitor substances or parameters to assure compliance with the permit or other applicable requirements.			
83	For applicable requirements that will become effective during the permit term, the Permittee shall meet such requirements on a timely basis.	Records Review and Interview with Responsible Personnel	Continuous	None

SECTION B
EMISSION UNITS

Form B: Emission Unit Listing for This Application

Forms B1: Emission Unit Detail Form - External Combustion Equipment

Forms B2: Emission Unit Detail Form - Internal Combustion Equipment

Forms B5: Miscellaneous Emission Units

FORM B
Emission Unit Listing For This Application

Permit Number: AQ0417TVP03

EMISSION UNIT LISTING: New, Modified, Previously Unpermitted, Replaced, Deleted					
Emission Unit ID Number	Emission Unit Name	Brief Emission Unit Description	Rating/ Size	Construction Date	Notes
Emission Units To Be ADDED By This Application (New, Previously Unpermitted, or Replacement)					
Emission Units To Be MODIFIED By This Application					
Emission Units To Be DELETED By This Application					

SIGNIFICANT EMISSION UNIT LISTING: Title V permitted emission units that have not been modified				
Emission Unit ID Number	Emission Unit Name	Brief Emission Unit Description	Rating/Size	Construction Date
420a	Generator	Cummins QSK50-G4	1,971 hp	Constructed in 2012; Installed in April 2013
421a	Generator	Cummins QSK50-G4	1,971 hp	Constructed 2010; Installed April 5, 2011
500	Turbine	Solar Mars 90	11,862 kW	1998
501	Turbine	Solar Mars 90	11,862 kW	1998
503	Production Heater	NATCO	34 MMBtu/hr	1998
505	TEG Reboiler	NATCO	1.34 MMBtu/hr	1998
507	Flare	Mac Ignitor 100 Series	257.9 MMscf/yr	1998
Drill Rig Equipment				
1	Rig Engines	Various	Various	Various
8	Rig Boilers and Heaters	Various	Various	Various

INSIGNIFICANT EMISSION UNIT LISTING: Insignificant Title V permitted emission units that have not been modified				
Emission Unit Name	Brief Emission Unit Description	Rating/Size	Construction Date	Basis for Insignificant Status
417	Diesel Tank	15,000 barrels	1998	18 AAC 50.326(e)
418	Methanol Tank	450 barrels	1998	18 AAC 50.326(e)
422	Smart Ash 100-A Cyclonic Burn Barrel	0.035 tons/hr	2003	18 AAC 50.326(e)
502	Therm-Tec-G-12 Incinerator	Propane/Fuel Gas – 1.6 MMBtu/hr Waste – 85.0 lb/hr	1998	18 AAC 50.326(e)
607	Indirect Fire Heater	1 MMBtu/hr	2008	18 AAC 50.326(f)(85)
608	Indirect Fire Heater	1 MMBtu/hr	2005	18 AAC 50.326(f)(85)
611	Indirect Fire Heater	1 MMBtu/hr	2008	18 AAC 50.326(f)(85)
612	Indirect Fire Heater	1 MMBtu/hr	2008	18 AAC 50.326(f)(85)
N/A	Hot Oil Burner	6 MMBtu/hr	2011	18 AAC 50.326(f)(85)

FORM B1

Emission Unit Detail Form – External Combustion Equipment (Boilers and Heaters)

Permit Number: AQ0417TVP03

1.	Emission Unit ID Number // Operating Scenario	Emission Unit 8
2.	Date installation/construction commenced	Various
3.	Date installed	Various
4.	Emission Unit serial number	Various
5.	Special control requirements? [if yes, describe]	No
6.	Manufacturer	Various
7.	Description of emission unit, including type of boiler/heater and firing method: Rig Heaters and Boilers EU ID 8 does not qualify as insignificant units per 18 AAC 50.326(d)(1) because the unit(s) are subject to operational limits and standards established under a Title I permit. However, EU ID 8 consists of small rig boilers and heaters that are insignificant based on size and/or have potential and/or actual emissions below the significant emissions thresholds in 18 AAC 50.326(e).	
8.	Rated design capacity (heat input, MMBtu/hr)	Various
9.	Maximum steam production rate (lbs/hr)	N/A
10.	Maximum steam pressure (psi)	N/A
11.	Maximum steam temperature (°F)	N/A

12. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Diesel and Fuel Gas	Not more than 9,000 gallons/day (includes rig engines). Fuel gas is converted to gallons equivalency (115 scf of fuel gas to one gallon diesel fuel).

13.	Is waste heat utilized for any purpose? If yes, describe: No

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 1	18 AAC 50.055(a)(1)	Visible Emissions	Do not cause or allow visible emissions to reduce visibility by more than 20 percent averaged over any six consecutive minutes.	Yes	Standard Permit Condition V
AQ0417TVP03 – Condition 6	18 AAC 50.055(b)(1)	Particulate Matter (PM) Emissions	Do not cause or allow particulate matter to exceed 0.05 grains per cubic foot of exhaust gas averaged over three hours.	Yes	Standard Permit Condition V
AQ0417TVP03 – Condition 10	18 AAC 50.055(c)	Sulfur Compound Emissions	Do not cause or allow sulfur compound emissions to exceed 500 ppm averaged over three hours.	Yes	Monitor, record, and report in accordance with Conditions 10.1 through 10.4 Standard Permit Condition V
AQ0417TVP03 – Condition 14	AQ0417MSS05 – Condition 9	SO_2 Limit to Protect Ambient Air Quality Standard	Operate using distillate fuel oil with a fuel sulfur content not to exceed 0.15 percent by weight (wt% S).	Yes	Monitor, record, and report in accordance with Conditions 10.1 through 10.4.
AQ0417TVP03 – Condition 16	AQ0417MSS07, Rev 1 – Condition 4	NO_2, SO_2, and PM_{10} Limit to Protect Ambient Air Quality Standard	In all drill rig emission units burn a combined total of no more than 9,000 gallons of liquid fuel per day and 950,000 gallons of liquid fuel during any 12 consecutive-month period	Yes	Monitor, record, and report in accordance with Conditions 16.1 through 16.4.
AQ0417TVP03 – Condition 17.3.a(ii)	AQ0417MSS05 – Condition 12.1.d(ii)	SO_2 Best Available Control Technology Limits	Sulfur content of fuel oil shall not exceed 0.15 wt% S.	Yes	Monitor, record, and report in accordance with Conditions 10.1 through 10.4, and 18.3
AQ0417TVP03 – Condition 17.4	AQ0417MSS05 – Condition 12.1.e	VOC Best Available Control Technology Limits	VOC BACT for fuel burning equipment is no controls with good operation practices. No emission limits are imposed as representing BACT.	Yes	Reasonable Inquiry
AQ0417TVP03 – Condition 17.5.a(iv)	AQ0417MSS05 – Condition 12.1.f(iii)	PM_{10} Best Available Control Technology Limits	Do not cause or allow visible emissions to reduce visibility by more than 20 percent averaged over any six consecutive minutes.	Yes	Standard Permit Condition V

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60 Subpart D	The emission unit heat input capacity is below the threshold (250 MMBtu/hr).
40 CFR 60 Subpart Da	The emission unit heat input capacity is below the threshold (250 MMBtu/hr); and the unit is not classified as Electric Utility Steam Generating Units, as defined in subpart.
40 CFR 60 Subpart Db	The emission unit heat input capacities are below the threshold (100 MMBtu/hr).
40 CFR 60 Subpart Dc	Any steam generating units used under EU ID 8 will have a maximum design heat input capacity less than 10 MMBtu/hr.
40 CFR 63 Subpart DDDDD	Stationary source is not a major source of hazardous air pollutants.
40 CFR 63 Subpart JJJJJJ	Any boilers used under EU ID 8 will meet the definition of temporary boiler under 40 CFR 63.11237 and is not subject per 40 CFR 63.11195(h).

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B1

Emission Unit Detail Form – External Combustion Equipment (Boilers and Heaters)

Permit Number: AQ0417TVP03

1.	Emission Unit ID Number // Operating Scenario	Emission Unit 503
2.	Date installation/construction commenced	1998
3.	Date installed	1998
4.	Emission Unit serial number	5A300
5.	Special control requirements? [if yes, describe]	Low NO_X burners/flue gas recirculation (Condition 17.1.a(iii))
6.	Manufacturer	NATCO
7.	Description of emission unit, including type of boiler/heater and firing method: Production Heater	
8.	Rated design capacity (heat input, MMBtu/hr)	34 MMBtu/hr
9.	Maximum steam production rate (lbs/hr)	N/A
10.	Maximum steam pressure (psi)	N/A
11.	Maximum steam temperature (°F)	N/A

12. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Fuel Gas	Approximately 33 Mscf/hr

13.	Is waste heat utilized for any purpose? If yes, describe: No

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 1	18 AAC 50.055(a)(1)	Visible Emissions	Do not cause or allow visible emissions to reduce visibility by more than 20 percent averaged over any six consecutive minutes.	Yes	Standard Permit Condition VIII
AQ0417TVP03 – Condition 6	18 AAC 50.055(b)(1)	Particulate Matter (PM) Emissions	Do not cause or allow particulate matter to exceed 0.05 grains per cubic foot of exhaust gas averaged over three hours.	Yes	Standard Permit Condition VIII
AQ0417TVP03 – Condition 10	18 AAC 50.055(c)	Sulfur Compound Emissions	Do not cause or allow sulfur compound emissions to exceed 500 ppm averaged over three hours.	Yes	Monitor, record, and report in accordance with Conditions 10.5 through 10.8.
AQ0417TVP03 – Condition 13	AQ0417MSS05 – Condition 8	SO_2 Limit to Protect Ambient Air Quality Standard	Operate using fuel gas with an H_2S content not to exceed 250 ppmv.	Yes	Monitor, record, and report in accordance with Conditions 10.5 through 10.8.
AQ0417TVP03 – Condition 17.1.a(iii)	AQ0417MSS05 – Condition 12.1.a(i)(C)	NO_X Best Available Control Technology Limits	Install and operate low NO_X burners/flue gas recirculation.	Yes	Reasonable Inquiry
AQ0417TVP03 – Condition 17.1.b(ii)	AQ0417MSS05 – Condition 12.1.a(ii)(B)	NO_X Best Available Control Technology Limits	NO_X emissions shall not exceed 0.095 lb/MMBtu.	Yes	Monitor, record, and report in accordance with Conditions 18.1.b.
AQ0417TVP03 – Condition 17.2.a(ii)	AQ0417MSS06, Rev 1 – Condition 2.1.b	CO Best Available Control Technology Limits	CO emissions shall not exceed 3.4 lb/hr.	Yes	Monitor, record, and report in accordance with Condition 18.1.b.
AQ0417TVP03 – Condition 17.3.a(i)	AQ0417MSS05 – Condition 12.1.d(i)	SO_2 Best Available Control Technology Limits	H_2S content of fuel gas shall not exceed 250 ppmv.	Yes	Monitor, record, and report in accordance with Conditions 10.5 through 10.8, and 18.3.
AQ0417TVP03 – Condition 17.4	AQ0417MSS05 – Condition 12.1.e	VOC Best Available Control Technology Limits	VOC BACT for fuel burning equipment is no controls with good operation practices. No emission limits are imposed as representing BACT.	Yes	Reasonable Inquiry

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 17.5.a(iv)	AQ0417MSS05 – Condition 12.1.f(iii)	PM_{10} Best Available Control Technology Limits	Do not cause or allow visible emissions to reduce visibility by more than 20 percent averaged over any six consecutive minutes.	Yes	Standard Permit Condition VIII
AQ0417TVP03 – Condition 23	40 CFR 60.7(b)	NSPS Subpart A Startup, Shutdown, and Malfunction Requirements	Maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of the emission unit and malfunctions of associated air-pollution control equipment.	Yes	Record Review
AQ0417TVP03 – Condition 27	40 CFR 60.11(d)	NSPS Subpart A Good Air Pollution Control Practice	At all time, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate the emission unit including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.	Yes	Reasonable Inquiry / Record Review
AQ0417TVP03 – Condition 30	40 CFR 60.48c(g)(2) & (i)	NSPS Subpart Dc Fuel Consumption	Record the amount of each fuel combusted during each operating month and maintain the records for a period of two years following the date of such record; or monitor according to an EPA approved custom fuel-monitoring schedule.	Yes	Monitor, record, and report in accordance with Condition 30.1.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60 Subpart D	The emission unit heat input capacity is below the threshold (250 MMBtu/hr).
40 CFR 60 Subpart Da	The emission unit heat input capacity is below the threshold (250 MMBtu/hr); and the unit is not classified as Electric Utility Steam Generating Units, as defined in subpart.
40 CFR 60 Subpart Db	The emission unit heat input capacity is below the threshold (100 MMBtu/hr).
40 CFR 63 Subpart DDDDD	The stationary source is not a major source of hazardous air pollutants (HAPs).

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B1

Emission Unit Detail Form – External Combustion Equipment (Boilers and Heaters)

Permit Number: AQ0417TVP03

1.	Emission Unit ID Number // Operating Scenario	Emission Unit 505
2.	Date installation/construction commenced	1998
3.	Date installed	1998
4.	Emission Unit serial number	8001-41
5.	Special control requirements? [if yes, describe]	No
6.	Manufacturer	NATCO
7.	Description of emission unit, including type of boiler/heater and firing method: TEG Reboiler	
8.	Rated design capacity (heat input, MMBtu/hr)	1.34 MMBtu/hr
9.	Maximum steam production rate (lbs/hr)	N/A
10.	Maximum steam pressure (psi)	N/A
11.	Maximum steam temperature (°F)	N/A

12. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Fuel Gas	Approximately 1 Mscf/hr

13.	Is waste heat utilized for any purpose? If yes, describe: No

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 1	18 AAC 50.055(a)(1)	Visible Emissions	Do not cause or allow visible emissions to reduce visibility by more than 20 percent averaged over any six consecutive minutes.	Yes	Standard Permit Condition VIII
AQ0417TVP03 – Condition 6	18 AAC 50.055(b)(1)	Particulate Matter (PM) Emissions	Do not cause or allow particulate matter to exceed 0.05 grains per cubic foot of exhaust gas averaged over three hours.	Yes	Standard Permit Condition VIII
AQ0417TVP03 – Condition 10	18 AAC 50.055(c)	Sulfur Compound Emissions	Do not cause or allow sulfur compound emissions to exceed 500 ppm averaged over three hours.	Yes	Monitor, record, and report in accordance with Conditions 10.5 through 10.8.
AQ0417TVP03 – Condition 13	AQ0417MSS05 – Condition 8	SO_2 Limit to Protect Ambient Air Quality Standard	Operate using fuel gas with an H_2S content not to exceed 250 ppmv.	Yes	Monitor, record, and report in accordance with Conditions 10.5 through 10.8.
AQ0417TVP03 – Condition 17.1.a(iv)	AQ0417MSS05 – Condition 12.1.a(i)(E)	NO_X Best Available Control Technology Limits	Install and operate conventional burner technology.	Yes	Reasonable Inquiry
AQ0417TVP03 – Condition 17.1.b(iii)	AQ0417MSS05 – Condition 12.1.a(ii)(D)	NO_X Best Available Control Technology Limits	NO_X emissions shall not exceed 0.08 lb/MMBtu.	Yes	Reasonable Inquiry
AQ0417TVP03 – Condition 17.2.a(iii)	AQ0417MSS06, Rev 1 – Condition 2.1.d	CO Best Available Control Technology Limits	CO emissions shall not exceed 0.15 lb/MMBtu.	Yes	Reasonable Inquiry
AQ0417TVP03 – Condition 17.3.a(i)	AQ0417MSS05 – Condition 12.1.d(i)	SO_2 Best Available Control Technology Limits	H_2S content of fuel gas shall not exceed 250 ppmv.	Yes	Monitor, record, and report in accordance with Conditions 10.5 through 10.8, and 18.3.
AQ0417TVP03 – Condition 17.4	AQ0417MSS05 – Condition 12.1.e	VOC Best Available Control Technology Limits	VOC BACT for fuel burning equipment is no controls with good operation practices. No emission limits are imposed as representing BACT.	Yes	Reasonable Inquiry

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 17.5.a(iv)	AQ0417MSS05 – Condition 12.1.f(iii)	PM_{10} Best Available Control Technology Limits	Do not cause or allow visible emissions to reduce visibility by more than 20 percent averaged over any six consecutive minutes.	Yes	Standard Permit Condition VIII Standard Permit Condition V
AQ0417TVP03 – Condition 49	18 AAC 50.346(b)(5)	Good Air Pollution Control Practices	Practice good maintenance for air pollution control.	Yes	Standard Permit Condition VI

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60 Subpart D	The emission unit heat input capacity is below the threshold (250 MMBtu/hr).
40 CFR 60 Subpart Da	The emission unit heat input capacity is below the threshold (250 MMBtu/hr); and the unit is not classified as Electric Utility Steam Generating Units, as defined in subpart.
40 CFR 60 Subpart Db	The emission unit heat input capacity is below the threshold (100 MMBtu/hr).
40 CFR 60 Subpart Dc	The emission unit heat input capacity is below the threshold (10 MMBtu/hr).
40 CFR 63 Subpart DDDDD	The stationary source is not a major source of hazardous air pollutants (HAPs).
40 CFR 63 Subpart JJJJJJ	Gas-fired boilers are not subject to Subpart JJJJJJ and to any requirements in this subpart (40 CFR 63.11195(e)).

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit Number: AQ0417TVP03

1.	Emission Unit ID Number // Operating Scenario	Emission Unit 1
2.	Date installation/construction commenced[1]	Various
3.	Date installed	Various
4.	Emission Unit serial number	Various
5.	Special control requirements? [if yes, describe]	No
6.	Manufacturer and model number	Various
7.	Type of combustion device	Nonroad Rig Engines
8.	Rated design capacity (horsepower rating for engines)	Various
9.	Rated design capacity (heat input, MMBtu/hr rating for turbines)	
10.	If used for power generation, electrical output (kW)	

1. See page 2 of the Form B instructions regarding installation/construction date and consult regulations under 40 C.F.R. 60 (NSPS) and 40 C.F.R. 63 (NESHAP) for applicability dates, e.g.,
- NSPS Subparts IIII and JJJJ, and NESHAP Subpart ZZZZ for engines, and
- NSPS Subparts GG and KKKK, and NESHAP Subpart YYYY for turbines.
Note that other regulations may apply in addition to the regulations cited.

11. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Diesel and Fuel Gas	Not more than 9,000 gallons/day (includes rig heaters and boilers). Fuel gas is converted to gallons equivalency (115 scf of fuel gas to one gallon diesel fuel).

12.	Describe any specific modifications to the emission unit that must be addressed in the permit: None

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 14	AQ0417MSS05 – Condition 9	SO_2 Limit to Protect Ambient Air Quality Standard	Operate using distillate fuel oil with a fuel sulfur content not to exceed 0.15 percent by weight.	Yes	Monitor, record, and report in accordance with Conditions 10.1 through 10.4.
AQ0417TVP03 – Condition 16	AQ0417MSS07, Rev 1 – Condition 4	NO_2, PM_{10}, and SO_2 Limit to Protect Ambient Air Quality Standard	In all drill rig emission units burn a combined total of no more than 9,000 gallons of liquid fuel per day and 950,000 gallons of liquid fuel during any 12 consecutive-month period	Yes	Monitor, record, and report in accordance with Conditions 16.1 through 16.4.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
18 AAC 50.055(a)(1), (b)(1), and (c)	Nonroad internal combustion engines are not included in the definition of "fuel-burning equipment" or industrial processes," as defined in 18 AAC 50.990(39) and (49).

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit Number: AQ0417TVP03

1.	Emission Unit ID Number // Operating Scenario	Emission Unit 420a
2.	Date installation/construction commenced[1]	2012
3.	Date installed	April 2013
4.	Emission Unit serial number	25384677
5.	Special control requirements? [if yes, describe]	A modular common rail system (MCRS) as incorporated by the manufacturer (Condition 17.1.a(i))
6.	Manufacturer and model number	Cummins QSK50-G4
7.	Type of combustion device	Diesel Generator Engine
8.	Rated design capacity (horsepower rating for engines)	1,971 hp
9.	Rated design capacity (heat input, MMBtu/hr rating for turbines)	
10.	If used for power generation, electrical output (kW)	1,470 kW

1. See page 2 of the Form B instructions regarding installation/construction date and consult regulations under 40 C.F.R. 60 (NSPS) and 40 C.F.R. 63 (NESHAP) for applicability dates, e.g.,
- NSPS Subparts IIII and JJJJ, and NESHAP Subpart ZZZZ for engines, and
- NSPS Subparts GG and KKKK, and NESHAP Subpart YYYY for turbines.
Note that other regulations may apply in addition to the regulations cited.

11. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Diesel	Approximately 100 gal/hr

12.	Describe any specific modifications to the emission unit that must be addressed in the permit: None

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 1	18 AAC 50.055(a)(1)	Visible Emissions	Do not cause or allow visible emissions to reduce visibility by more than 20 percent averaged over any six consecutive minutes.	Yes	Standard Permit Condition IX
AQ0417TVP03 – Condition 6	18 AAC 50.055(b)(1)	Particulate Matter (PM) Emissions	Do not cause or allow particulate matter to exceed 0.05 grains per cubic foot of exhaust gas averaged over three hours.	Yes	Standard Permit Condition IX
AQ0417TVP03 – Condition 10	18 AAC 50.055(c)	Sulfur Compound Emissions	Do not cause or allow sulfur compound emissions to exceed 500 ppm averaged over three hours.	Yes	Standard Permit Condition XI
AQ0417TVP03 – Condition 14	AQ0417MSS05 – Condition 9	Limit to Protect SO_2 Ambient Air Quality Standard	Operate using distillate fuel oil with a fuel sulfur content not to exceed 0.15 percent by weight.	Yes	Monitor, record, and report in accordance with Conditions 10.1 through 10.4.
AQ0417TVP03 – Condition 15	AQ0417MSS05 – Condition 10	Limit to Protect NO_2, SO_2, and PM_{10} Ambient Air Quality Standards	For EU IDs 420a and 421a burn a combined total of no more than 800,000 gallons of liquid fuel during any 12 consecutive-month period.	Yes	Monitor, record, and report in accordance with Conditions 15.1 through 15.6.
AQ0417TVP03 – Condition 17.1.a(i)	AQ0417MSS05 – Condition 12.1.a(i)(B)	NO_X Best Available Control Technology Limits	Install and operate a modular common rail system (MCRS) as incorporated by the manufacturer.	Yes	Reasonable Inquiry
AQ0417TVP03 – Condition 17.3.a(ii)	AQ0417MSS05 – Condition 12.1.d(ii)	SO_2 Best Available Control Technology Limits	Sulfur content of fuel oil shall not exceed 0.15 wt% S.	Yes	Monitor, record, and report in accordance with Conditions 10.1 through 10.4, and 18.3
AQ0417TVP03 – Condition 17.4	AQ0417MSS05 – Condition 12.1.e	VOC Best Available Control Technology Limits	VOC BACT for fuel burning equipment is no controls with good operation practices. No emission limits are imposed as representing BACT.	Yes	Reasonable Inquiry

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 17.5a(i) and (ii)	AQ0417MSS05 Condition 12.1.f	PM_{10} Best Available Control Technology Limits	Visible emissions shall not exceed 20 percent opacity averaged over any six consecutive minutes, except if both oil and gas production cease for 30 consecutive days, visible emissions shall not exceed 10 percent opacity averaged over any six consecutive minutes, until oil and gas production resumes.	Yes	Monitor, record, and report in accordance with Conditions 18.4a and 18.5.
AQ0417TVP03 – Condition 29	40 CFR 60.12	NSPS Subpart A Concealment of Emissions	Do not build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard.	Yes	Reasonable Inquiry
AQ0417TVP03 – Condition 35	40 CFR 60.4200(a)(2)(i)	NSPS Subpart IIII Applicability and General Compliance Requirements	Comply with the applicable requirements for a non-emergency stationary compression ignition (CI) internal combustion engine (ICE) whose construction commences after July 11, 2005, where the stationary CI ICE is manufactured after April 1, 2006.	Yes	Monitor, record, and report in accordance with Conditions 37 and 38.
AQ0417TVP03 – Condition 35.1	40 CFR 60.4206 and 60.4211(a)	NSPS Subpart IIII Applicability and General Compliance Requirements	Operate and maintain the stationary CI ICE and control device according to the manufacturer's written instructions or procedures developed by the Permittee that are approved by the engine manufacturer over the entire life of the engine. In addition, the Permittee may only change those settings that are permitted by the manufacturer.	Yes	Monitor, record, and report in accordance with Conditions 37 and 38.

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 35.2	40 CFR 60.4218 and Table 8 of Subpart IIII	NSPS Subpart IIII Applicability and General Compliance Requirements.	Comply with the applicable provisions of Subpart A as specified in Table 8 to Subpart IIII.	Yes	Monitor, record, and report in accordance with Conditions 37 and 38.
AQ0417TVP03 – Condition 36	40 CFR 60.4216(c), 60.4205(b) & 60.4202(a)(2)	NSPS Subpart IIII Emission Standards	Comply with the applicable emission standards.	Yes	Monitor, record, and report in accordance with Conditions 37 and 38.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60.7	Only applies as specified in 40 CFR 60.4214(a), non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified (Table 8 to Subpart IIII of Part 60).
40 CFR 60.8	Only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified (Table 8 to Subpart IIII of Part 60).
40 CFR 60.11	Requirements are specified in 40 CFR 60 Subpart IIII (Table 8 to Subpart IIII of Part 60).
40 CFR 60.4207	According to 40 CFR 60.4216(d), the provisions of 40 C.F.R. 60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE that are located in areas of Alaska not accessible by the Federal Aid Highway System (FAHS).
40 CFR 60.4209(b) & 60.4214(c)	Emission unit is a non-emergency CI ICE not equipped with a diesel particulate filter to comply with the emission standards in 40 CFR 60.4204.
40 CFR 60.4214(a)	Emission unit is not greater than 2,237 kW (3,000 hp), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified.
40 CFR 60.4212 & 60.4213	Performance testing is not required. The emission unit meets the standards by being an engine certified to the applicable emission standards.
40 CFR 63 Subpart ZZZZ	Emission unit is a new stationary CI RICE and meets the requirements of 40 CFR 63 Subpart ZZZZ by meeting the requirements of 40 CFR 60 Subpart IIII and no further requirements apply (40 CFR 63.6590(c)(1)).

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit Number: AQ0417TVP03

1.	Emission Unit ID Number // Operating Scenario	Emission Unit 421a
2.	Date installation/construction commenced[1]	2010
3.	Date installed	April 5, 2011
4.	Emission Unit serial number	33183042
5.	Special control requirements? [if yes, describe]	A modular common rail system (MCRS) as incorporated by the manufacturer (Condition 17.1.a(i))
6.	Manufacturer and model number	Cummins QSK50-G4
7.	Type of combustion device	Diesel Generator Engine
8.	Rated design capacity (horsepower rating for engines)	1,971 hp
9.	Rated design capacity (heat input, MMBtu/hr rating for turbines)	
10.	If used for power generation, electrical output (kW)	1,470 kW

1. See page 2 of the Form B instructions regarding installation/construction date and consult regulations under 40 C.F.R. 60 (NSPS) and 40 C.F.R. 63 (NESHAP) for applicability dates, e.g.,
- NSPS Subparts IIII and JJJJ, and NESHAP Subpart ZZZZ for engines, and
- NSPS Subparts GG and KKKK, and NESHAP Subpart YYYY for turbines.
Note that other regulations may apply in addition to the regulations cited.

11. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Diesel	Approximately 100 gal/hr

12.	Describe any specific modifications to the emission unit that must be addressed in the permit: None

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 1	18 AAC 50.055(a)(1)	Visible Emissions	Do not cause or allow visible emissions to reduce visibility by more than 20 percent averaged over any six consecutive minutes.	Yes	Standard Permit Condition IX
AQ0417TVP03 – Condition 6	18 AAC 50.055(b)(1)	Particulate Matter (PM) Emissions	Do not cause or allow particulate matter to exceed 0.05 grains per cubic foot of exhaust gas averaged over three hours.	Yes	Standard Permit Condition IX
AQ0417TVP03 – Condition 10	18 AAC 50.055(c)	Sulfur Compound Emissions	Do not cause or allow sulfur compound emissions to exceed 500 ppm averaged over three hours.	Yes	Standard Permit Condition XI
AQ0417TVP03 – Condition 14	AQ0417MSS05 – Condition 9	Limit to Protect SO_2 Ambient Air Quality Standard	Operate using distillate fuel oil with a fuel sulfur content not to exceed 0.15 percent by weight.	Yes	Monitor, record, and report in accordance with Conditions 10.1 through 10.4.
AQ0417TVP03 – Condition 15	AQ0417MSS05 – Condition 10	Limit to Protect NO_2, SO_2, and PM_{10} Ambient Air Quality Standard	For EU IDs 420a and 421a burn a combined total of no more than 800,000 gallons of liquid fuel during any 12 consecutive-month period.	Yes	Monitor, record, and report in accordance with Conditions 15.1 through 15.6.
AQ0417TVP03 – Condition 17.1.a(i)	AQ0417MSS05 – Condition 12.1.a(i)(B)	NO_X Best Available Control Technology Limits	Install and operate a modular common rail system (MCRS) as incorporated by the manufacturer.	Yes	Reasonable Inquiry
AQ0417TVP03 – Condition 17.3.a(ii)	AQ0417MSS05 – Condition 12.1.d(ii)	SO_2 Best Available Control Technology Limits	Sulfur content of fuel oil shall not exceed 0.15 wt% S.	Yes	Monitor, record, and report in accordance with Conditions 10.1 through 10.4, and 18.3.
AQ0417TVP03 – Condition 17.4	AQ0417MSS05 – Condition 12.1.e	VOC Best Available Control Technology Limits	VOC BACT for fuel burning equipment is no controls with good operation practices. No emission limits are imposed as representing BACT.	Yes	Reasonable Inquiry

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 17.5a(i) and a(ii)	AQ0417MSS05 – Condition 12.1.f	PM_{10} Best Available Control Technology Limits	Visible emissions shall not exceed 20 percent opacity averaged over any six consecutive minutes, except if both oil and gas production cease for 30 consecutive days, visible emissions shall not exceed 10 percent opacity averaged over any six consecutive minutes, until oil and gas production resumes.	Yes	Monitor, record, and report in accordance with Conditions 18.4a.
AQ0417TVP03 – Condition 29	40 CFR 60.12	NSPS Subpart A Concealment of Emissions	Do not build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard.	NA	Reasonable Inquiry
AQ0417TVP03 – Condition 35	40 CFR 60.4200(a)(2)(i)	NSPS Subpart IIII Applicability and General Compliance Requirements	Comply with the applicable requirements for a non-emergency stationary compression ignition (CI) internal combustion engine (ICE) whose construction commences after July 11, 2005 where the stationary CI ICE is manufactured after April 1, 2006.	Yes	Monitor, record, and report in accordance with Conditions 37 and 38.
AQ0417TVP03 – Condition 35.1	40 CFR 60.4206 and 60.4211(a)	NSPS Subpart IIII Applicability and General Compliance Requirements	Operate and maintain the stationary CI ICE and control device according to the manufacturer's written instructions or procedures developed by the Permittee that are approved by the engine manufacturer over the entire life of the engine. In addition, the Permittee may only change those settings that are permitted by the manufacturer.	Yes	Monitor, record, and report in accordance with Conditions 37 and 38.

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 35.2	40 CFR 60.4218 and Table 8 of Subpart IIII	NSPS Subpart IIII Applicability and General Compliance Requirements.	Comply with the applicable provisions of Subpart A as specified in Table 8 to Subpart IIII.	Yes	Monitor, record, and report in accordance with Conditions 37 and 38.
AQ0417TVP03 – Condition 36	40 CFR 60.4216(c), 60.4205(b) & 60.4202(a)(2)	NSPS Subpart IIII Emission Standards	Comply with the applicable emission standards.	Yes	Monitor, record, and report in accordance with Conditions 37 and 38.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60.7	Only applies as specified in 40 CFR 60.4214(a), non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified (Table 8 to Subpart IIII of Part 60).
40 CFR 60.8	Only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified (Table 8 to Subpart IIII of Part 60).
40 CFR 60.11	Requirements are specified in 40 CFR 60 Subpart IIII (Table 8 to Subpart IIII of Part 60).
40 CFR 60.4207	According to 40 CFR 60.4216(d), the provisions of 40 C.F.R. 60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE that are located in areas of Alaska not accessible by the Federal Aid Highway System (FAHS).
40 CFR 60.4209(b) & 60.4214(c)	Emission unit is a non-emergency CI ICEs not equipped with a diesel particulate filter to comply with the emission standards in 40 CFR 60.4204.
40 CFR 60.4214(a)	Emission unit is not greater than 2,237 kW (3,000 hp), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified.
40 CFR 60.4212 & 60.4213	Performance testing is not required. The emission unit meets the standards by being an engine certified to the applicable emission standards.
40 CFR 63 Subpart ZZZZ	Emission unit is a new stationary CI RICE and meets the requirements of 40 CFR 63 Subpart ZZZZ by meeting the requirements of 40 CFR 60 Subpart IIII and no further requirements apply (40 CFR 63.6590(c)(1)).

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit Number: AQ0417TVP03

1.	Emission Unit ID Number // Operating Scenario	Emission Unit 500
2.	Date installation/construction commenced[1]	1998
3.	Date installed	1998
4.	Emission Unit serial number	0456M
5.	Special control requirements? [if yes, describe]	Dry low NO_X combustion technology (SoLoNO_X) (Condition 17.1.a(ii))
6.	Manufacturer and model number	Solar Mars 90
7.	Type of combustion device	Turbine
8.	Rated design capacity (horsepower rating for engines)	
9.	Rated design capacity (heat input, MMBtu/hr rating for turbines)	127 MMBtu/hr
10.	If used for power generation, electrical output (kW)	11,862 kW

[1] See page 2 of the Form B instructions regarding installation/construction date and consult regulations under 40 C.F.R. 60 (NSPS) and 40 C.F.R. 63 (NESHAP) for applicability dates, e.g.,
- NSPS Subparts IIII and JJJJ, and NESHAP Subpart ZZZZ for engines, and
- NSPS Subparts GG and KKKK, and NESHAP Subpart YYYY for turbines.
Note that other regulations may apply in addition to the regulations cited.

11. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Fuel Gas	Approximately 122 Mscf/hr

12.	Describe any specific modifications to the emission unit that must be addressed in the permit: None

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 1	18 AAC 50.055(a)(1)	Visible Emissions	Do not cause or allow visible emissions to reduce visibility by more than 20 percent averaged over any six consecutive minutes.	Yes	Standard Permit Condition VIII
AQ0417TVP03 – Condition 6	18 AAC 50.055(b)(1)	Particulate Matter (PM) Emissions	Do not cause or allow particulate matter to exceed 0.05 grains per cubic foot of exhaust gas averaged over three hours.	Yes	Standard Permit Condition VIII
AQ0417TVP03 – Condition 10	18 AAC 50.055(c)	Sulfur Compound Emissions	Do not cause or allow sulfur compound emissions to exceed 500 ppm averaged over three hours.	Yes	Monitor, record, and report in accordance with Conditions 10.5 through 10.8.
AQ0417TVP03 – Condition 13	AQ0417MSS05 – Condition 8	Limit to Protect SO_2 Ambient Air Quality Standard	Operate using fuel gas with an H_2S content not to exceed 250 ppmv.	Yes	Monitor, record, and report in accordance with Conditions 10.5 through 10.8.
AQ0417TVP03 – Condition 17.1.a(ii)	AQ0417MSS05 – Condition 12.1.a(i)(A)	NO_X Best Available Control Technology Limits	Install and operate dry low NO_X combustion technology ($SoLoNO_X$).	Yes	Reasonable Inquiry
AQ0417TVP03 – Condition 17.1.b(i)	AQ0417MSS05 – Condition 12.1.a(ii)(A)	NO_X Best Available Control Technology Limits	NO_X emissions shall not exceed 28.4 lb/hr for operation under all conditions and shall not exceed 85 ppmv corrected to 15 percent oxygen in $SoLoNO_X$ mode and at ambient temperatures above 0ºF.	Yes	Monitor, record, and report in accordance with Condition 18.1.

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 17.2.a(i)	AQ0417MSS06 – Condition 2.1.a	CO Best Available Control Technology Limits	CO emissions shall not exceed 50 ppmv corrected to 15 percent oxygen when operating at 100 percent load in $SoLoNO_X$ mode and at ambient temperatures above 0ºF, 14 lb/hr when operating in $SoLoNO_X$ mode and at ambient temperatures above 0ºF, and 385 lb/hr for operation under all other conditions.	Yes	Monitor, record, and report in accordance with Conditions 18.1.a, 18.2, and 18.5.
AQ0417TVP03 – Condition 17.2.b	AQ0417MSS05 – Condition 12.1.c	CO Best Available Control Technology Limits	Limit CO emissions from EU IDs 500 and 501, combined, to no greater than 336 tons per 12 consecutive-month period.	Yes	Monitor, record, and report in accordance with Condition 18.1.a, 18.2, and 18.5.
AQ0417TVP03 – Condition 17.3.a(i)	AQ0417MSS05 – Condition 12.1.d(i)	SO_2 Best Available Control Technology Limits	H_2S content of fuel gas shall not exceed 250 ppmv.	Yes	Monitor, record, and report in accordance with Conditions 10.5 through 10.8, 18.3, and 18.5.
AQ0417TVP03 – Condition 17.4	AQ0417MSS05 – Condition 12.1.e	VOC Best Available Control Technology Limits	VOC BACT for fuel burning equipment is no controls with good operation practices. No emission limits are imposed as representing BACT.	Yes	Reasonable Inquiry
AQ0417TVP03 – Condition 17.5a(iii)	AQ0417MSS05 – Condition 12.1.f	PM_{10} Best Available Control Technology Limits	Visible emissions shall not exceed 10 percent opacity averaged over any six consecutive minutes.	Yes	Standard Permit Condition VIII Monitor, record, and report in accordance with Conditions 1.3 and 18.5.

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Conditions 19 and 20	AQ0417MSS05 – Conditions 13 and 14	Limits on Use of Load Banks Load Bank Exception	Except as provided below, after February 1, 2013, do not use load banks, water brakes, pump flow controls or other loads that have the single purpose to destroy energy in order to improve the CO emission performance of EU IDs 500 and 501. For purposes of this permit, a load bank is a resistance device that performs no process or space heating function. A load bank may be used on a short-term basis to address intermittent power fluctuations that may occur as a result of bringing on a second turbine for project ramp-up, with the plan of operating both turbines simultaneously.	Yes	Monitor, record, and report in accordance with Condition 20.1 through 20.3.
AQ0417TVP03 – Condition 23	40 CFR 60.7(b)	NSPS Subpart A Startup, Shutdown, and Malfunction Requirements	Maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of the emission unit and malfunctions of associated air-pollution control equipment.	Yes	Record Review
AQ0417TVP03 – Condition 24	40 CFR 60.7(c)	NSPS Subpart A Excess Emissions and Monitoring Systems Performance Report	Submit Excess Emission and Monitoring Systems Performance Report (EEMSP) as specified in this Condition.	Yes	Record Review
AQ0417TVP03 – Condition 25	40 CFR 60.7(d)	NSPS Subpart A Summary Report Form	Submit to ADEC and EPA semiannually a summary report form or EEMSP as specified in this Condition.	Yes	Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 26	40 CFR 60.8	NSPS Subpart A Performance (Source) Tests	Conduct performance tests according to 40 CFR 60.8 and Section 6 of the TV Permit at such other times as may be required by EPA and provide the ADEC and EPA with a written report of the results.	Yes	Record Review
AQ0417TVP03 – Condition 27	40 CFR 60.11(d)	NSPS Subpart A Good Air Pollution Control Practice	At all time, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate the emission unit including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.	Yes	Reasonable Inquiry / Record Review
AQ0417TVP03 – Condition 28	40 CFR 60.11(g)	NSPS Subpart A Credible Evidence	For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of the standards set forth in Conditions 31 and 32 nothing in 40 CFR Part 60 shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether EU ID 500 would have been in compliance with applicable requirements of 40 CFR Part 60 if the appropriate performance or compliance test or procedure had been performed.	N/A	Information condition only

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 29	40 CFR 60.12	NSPS Subpart A Concealment of Emissions	The Permittee shall not build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard.	Yes	Reasonable Inquiry
AQ0417TVP03 – Condition 31	40 CFR 60.332(a)(2) & (d)	NSPS Subpart GG NO_X Standard	Do not allow the exhaust gas concentration of NO_X to exceed 191 ppmvd at 15 percent O_2, ISO, dry exhaust basis.	Yes	Monitor, record, and report according to Conditions 32.2 through 32.4.
AQ0417TVP02, Rev 2 – Condition 33	40 CFR 60.333(b)	NSPS Subpart GG SO_2 Standard	Do not allow the sulfur content for the fuel burned in EU to exceed 0.8 percent by weight.		Monitor, record, and report according to Condition 34.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60.7(a)(1) & (3), 60.8(a)	Obsolete requirements. Initial notification and performance testing completed.
40 CFR 60.7(a)(4)	This requirement only applies to "existing facilities," as defined in 40 CFR 60.2.
40 CFR 60.332(a)(1)	Emission unit is not an Electric Utility Stationary Gas Turbine as defined in 40 CFR 60 Subpart GG.
40 CFR 60.334(a), (b), & (d), and 60.335(b)(4)	Emission unit is not equipped with water injection to control emissions of NO_X.
40 CFR 60.334(e) & (f)	Emission unit commenced construction prior to July 8, 2004.
40 CFR 60.334(g)	Emission unit is not subject to continuous monitoring requirements in 40 CFR 60.334(a), (d), or (f).
40 CFR 60.334(h)(2)	The allowance for fuel bound nitrogen to calculate the NO_X emission limit under 40 CFR 60.332 has not been claimed.
40 CFR 60 Subpart KKKK	Emission unit has not commenced construction, modification, or reconstruction after February 18, 2005.
40 CFR 63 Subpart YYYY	The affected facility is not a major source of hazardous air pollutants (HAPs).

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit Number: AQ0417TVP03

1.	Emission Unit ID Number // Operating Scenario	Emission Unit 501
2.	Date installation/construction commenced[1]	1998
3.	Date installed	1998
4.	Emission Unit serial number	0455M
5.	Special control requirements? [if yes, describe]	Dry low NO_X combustion technology ($SoLoNO_X$) (Condition 17.1.a(i))
6.	Manufacturer and model number	Solar Mars 90
7.	Type of combustion device	Turbine
8.	Rated design capacity (horsepower rating for engines)	
9.	Rated design capacity (heat input, MMBtu/hr rating for turbines)	127 MMBtu/hr
10.	If used for power generation, electrical output (kW)	11,862 kW

[1] See page 2 of the Form B instructions regarding installation/construction date and consult regulations under 40 C.F.R. 60 (NSPS) and 40 C.F.R. 63 (NESHAP) for applicability dates, e.g.,
- NSPS Subparts IIII and JJJJ, and NESHAP Subpart ZZZZ for engines, and
- NSPS Subparts GG and KKKK, and NESHAP Subpart YYYY for turbines.
Note that other regulations may apply in addition to the regulations cited.

11. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Fuel Gas	Approximately 122 Mscf/hr

12.	Describe any specific modifications to the emission unit that must be addressed in the permit: None

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 1	18 AAC 50.055(a)(1)	Visible Emissions	Do not cause or allow visible emissions to reduce visibility by more than 20 percent averaged over any six consecutive minutes.	Yes	Standard Permit Condition VIII
AQ0417TVP03 – Condition 6	18 AAC 50.055(b)(1)	Particulate Matter (PM) Emissions	Do not cause or allow particulate matter to exceed 0.05 grains per cubic foot of exhaust gas averaged over three hours.	Yes	Standard Permit Condition VIII
AQ0417TVP03 – Condition 10	18 AAC 50.055(c)	Sulfur Compound Emissions	Do not cause or allow sulfur compound emissions to exceed 500 ppm averaged over three hours.	Yes	Monitor, record, and report in accordance with Conditions 10.5 through 10.8.
AQ0417TVP03 – Condition 13	AQ0417MSS05 Condition 8	Limit to Protect SO_2 Ambient Air Quality Standard	Operate using fuel gas with an H_2S content not to exceed 250 ppmv.	Yes	Monitor, record, and report in accordance with Conditions 10.5 through 10.8.
AQ0417TVP03 – Condition 17.1.a(ii)	AQ0417MSS05 Condition 12.1.a(i)(A)	NO_X Best Available Control Technology Limits	Install and operate dry low NO_X combustion technology ($SoLoNO_X$).	Yes	Reasonable Inquiry
AQ0417TVP03 – Condition 17.1.b(i)	AQ0417MSS05 Condition 12.1.a(ii)(A)	NO_X Best Available Control Technology Limits	NO_X emissions shall not exceed 28.4 lb/hr for operation under all conditions and shall not exceed 85 ppmv corrected to 15 percent oxygen in $SoLoNO_X$ mode and at ambient temperatures above 0ºF.	Yes	Monitor, record, and report in accordance with Conditions 18.1.

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 17.2.a(i)	AQ0417MSS06 – Condition 2.1.a	CO Best Available Control Technology Limits	CO emissions shall not exceed 50 ppmv corrected to 15 percent oxygen when operating at 100 percent load in $SoLoNO_X$ mode and at ambient temperatures above 0ºF, 14 lb/hr when operating in $SoLoNO_X$ mode and at ambient temperatures above 0ºF, and 385 lb/hr for operation under all other conditions.	Yes	Monitor, record, and report in accordance with Conditions 18.1.a, 18.2, and 18.5.
AQ0417TVP03 – Condition 17.2.b	AQ0417MSS05 – Condition 12.1.c	CO Best Available Control Technology Limits	Limit CO emissions from EU IDs 500 and 501, combined, to no greater than 336 tons per 12 consecutive-month period.	Yes	Monitor, record, and report in accordance with Condition 18.1.a, 18.2, and 18.5.
AQ0417TVP03 – Condition 17.3.a(i)	AQ0417MSS05 – Condition 12.1.d(i)	SO_2 Best Available Control Technology Limits	H_2S content of fuel gas shall not exceed 250 ppmv.	Yes	Monitor, record, and report in accordance with Conditions 10.5 through 10.8, 18.3, and 18.5.
AQ0417TVP03 – Condition 17.4	AQ0417MSS05 – Condition 12.1.e	VOC Best Available Control Technology Limits	VOC BACT for fuel burning equipment is no controls with good operation practices. No emission limits are imposed as representing BACT.	Yes	Reasonable Inquiry
AQ0417TVP03 – Condition 17.5a(iii)	AQ0417MSS05 – Condition 12.1.f	PM_{10} Best Available Control Technology Limits	Visible emissions shall not exceed 10 percent opacity averaged over any six consecutive minutes.	Yes	Standard Permit Condition VIII Monitor, record, and report in accordance with Conditions 1.3 and 18.5.

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Conditions 19 and 20	AQ0417MSS05 – Conditions 13 and 14	Limits on Use of Load Banks Load Bank Exception	Except as provided below, after February 1, 2013, do not use load banks, water brakes, pump flow controls or other loads that have the single purpose to destroy energy in order to improve the CO emission performance of EU IDs 500 and 501. For purposes of this permit, a load bank is a resistance device that performs no process or space heating function. A load bank may be used on a short term basis to address intermittent power fluctuations that may occur as a result of bringing on a second turbine for project ramp-up, with the plan of operating both turbines simultaneously.	Yes	Monitor, record, and report in accordance with Condition 20.1 through 20.2.
AQ0417TVP03 – Condition 23	40 CFR 60.7(b)	NSPS Subpart A Startup, Shutdown, and Malfunction Requirements	Maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of the emission unit and malfunctions of associated air-pollution control equipment.	Yes	Record Review
AQ0417TVP03 – Condition 24	40 CFR 60.7(c)	NSPS Subpart A Excess Emissions and Monitoring Systems Performance Report	Submit Excess Emission and Monitoring Systems Performance Report (EEMSP) as specified in this Condition.	Yes	Record Review
AQ0417TVP03 – Condition 25	40 CFR 60.7(d)	NSPS Subpart A Summary Report Form	Submit to ADEC and EPA semiannually a summary report form or EEMSP as specified in this Condition.	Yes	Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 26	40 CFR 60.8	NSPS Subpart A Performance (Source) Tests	Conduct performance tests according to 40 CFR 60.8 and Section 6 of the TV Permit at such other times as may be required by EPA and provide the ADEC and EPA with a written report of the results.	Yes	Record Review
AQ0417TVP03 – Condition 27	40 CFR 60.11(d)	NSPS Subpart A Good Air Pollution Control Practice	At all time, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate the emission unit including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.	Yes	Reasonable Inquiry / Record Review
AQ0417TVP03 – Condition 28	40 CFR 60.11(g)	NSPS Subpart A Credible Evidence	For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of the standards set forth in Conditions 32 and 33 nothing in 40 CFR Part 60 shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether EU ID 500 would have been in compliance with applicable requirements of 40 CFR Part 60 if the appropriate performance or compliance test or procedure had been performed.	N/A	Information condition only

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 29	40 CFR 60.12	NSPS Subpart A Concealment of Emissions	The Permittee shall not build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard.	Yes	Reasonable Inquiry
AQ0417TVP03 – Condition 31	40 CFR 60.332(a)(2) & (d)	NSPS Subpart GG NO_X Standard	Do not allow the exhaust gas concentration of NO_X to exceed 191 ppmvd at 15 percent O_2, ISO, dry exhaust basis.	Yes	Monitor, record, and report according to Conditions 32.2 through 32.4.
AQ0417TVP02, Rev 2 – Condition 33	40 CFR 60.333(b)	NSPS Subpart GG SO_2 Standard	Do not allow the sulfur content for the fuel burned in EU to exceed 0.8 percent by weight.		Monitor, record, and report according to Condition 34.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60.7(a)(1) & (3), 60.8(a)	Obsolete requirements. Initial notification and performance testing completed.
40 CFR 60.7(a)(4)	This requirement only applies to "existing facilities," as defined in 40 CFR 60.2.
40 CFR 60.332(a)(1)	Emission unit is not an Electric Utility Stationary Gas Turbine as defined in 40 CFR 60 Subpart GG.
40 CFR 60.334(a), (b), & (d), and 60.335(b)(4)	Emission unit is not equipped with water injection to control emissions of NO_X.
40 CFR 60.334(e) & (f)	Emission unit commenced construction prior to July 8, 2004.
40 CFR 60.334(g)	Emission unit is not subject to continuous monitoring requirements in 40 CFR 60.334(a), (d), or (f).
40 CFR 60.334(h)(2)	The allowance for fuel bound nitrogen to calculate the NO_X emission limit under 40 CFR 60.332 has not been claimed.
40 CFR 60 Subpart KKKK	Emission unit has not commenced construction, modification, or reconstruction after February 18, 2005.
40 CFR 63 Subpart YYYY	The affected facility is not a major source of hazardous air pollutants (HAPs).

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B5
Emission Unit Detail Form - Miscellaneous Emission Units

Permit Number: AQ0062TVP03

1.	Emission Unit ID Number // Operating Scenario	Emission Unit 507
2.	Date installation/construction commenced	1998
3.	Date installed	1998
4.	Emission Unit serial number	Not Available
5.	Special control requirements? [if yes, describe]	No
6.	Description of process: Mac Ignitor 100 Series	
7.	Continuous or batch process? [if batch, maximum batches per hour]	N/A

8. Raw material usage: [for EACH raw material used, enter]:

Material	Maximum design capacity (lbs/batch or lbs/hr)
Fuel Gas and Produced Gas	257.9 MMscf/yr

9. Production data: [for EACH product, enter]:

Product	Maximum design capacity (lbs/batch or lbs/hr)
N/A	N/A

10. Attach any additional information necessary to describe this process and its operating and usage parameters, both short-term and annual.

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 1	18 AAC 50.055(a)(1)	Visible Emissions	Do not cause or allow visible emissions to reduce visibility by more than 20 percent averaged over any six consecutive minutes.	Yes	Standard Permit Condition IX
AQ0417TVP03 – Condition 6	18 AAC 50.055(b)(1)	Particulate Matter (PM) Emissions	Do not cause or allow particulate matter to exceed 0.05 grains per cubic foot of exhaust gas averaged over three hours.	Yes	Standard Permit Condition IX
AQ0417TVP03 – Condition 10	18 AAC 50.055(c)	Sulfur Compound Emissions	Do not cause or allow sulfur compound emissions to exceed 500 ppm averaged over three hours.	Yes	Monitor, record, and report in accordance with Conditions 10.5 through 10.8.
AQ0417TVP03 – Condition 11	AQ0417MSS05 – Condition 7.1	Limit to Protect Ambient Air Quality Standard	Flare fuel gas and produced gas during routine or non-routine maintenance activities and other planned events. Flare fuel gas and produced gas quantities no greater than 152 MMscf during any 12 consecutive-month period, at a rate of no greater than 20 MMscf per day.	Yes	Monitor, record, and report in accordance with Conditions 11.1 through 11.3.
AQ0417TVP03 – Condition 13	AQ0417MSS05 – Condition 8	SO_2 Limit to Protect Ambient Air Quality Standard	Operate using fuel gas and produced gas with an H_2S content not to exceed 250 ppmv.	Yes	Monitor, record, and report in accordance with Conditions 10.5 through 10.8.
AQ0417TVP03 – Condition 17.3.a(i)	AQ0417MSS05 – Condition 12.1.d(i)	SO_2 Best Available Control Technology Limits	H_2S content of fuel gas and produced fuel shall not exceed 250 ppmv.	Yes	Monitor, record, and report in accordance with Conditions 10.5 through 10.8, and 18.3.
AQ0417TVP03 – Condition 17.4	AQ0417MSS05 – Condition 12.1.e	VOC Best Available Control Technology Limits	VOC BACT for fuel burning equipment is no controls with good operation practices. The flare BACT determination is smokeless tip design. No emission limits are imposed as representing BACT.	Yes	Reasonable Inquiry

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0417TVP03 – Condition 17.5.a(iv)	AQ0417MSS05 – Condition 12.1.f(iii)	PM_{10} Best Available Control Technology Limits	Do not cause or allow visible emissions to reduce visibility by more than 20 percent averaged over any six consecutive minutes.	Yes	Standard Permit Condition VIII Standard Permit Condition V
AQ0417TVP03 – Condition 49	18 AAC 50.346(b)(5)	Good Air Pollution Control Practices	Practice good maintenance for air pollution control.	Yes	Standard Permit Condition VI

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60.18	This flare is not a control device used to comply with applicable Subparts of 40 CFR 60 and 40 CFR 61.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

SECTION C
POLLUTION CONTROL DEVICES

Not Applicable

SECTION D
EMISSIONS SUMMARY

Section D1: Emissions Unit Summary of Actual Emissions

Section D2: Emissions Unit Summary of Potential Emissions (Before Controls/Limitations)

Section D3: Emissions Unit Summary of Potential Emissions (After Controls/Limitations)

Table D1-1. Actual Annual Emissions (After Controls/Limitations) Summary
Savant Alaska, LLC - Badami Development Facility

Potential to Emit	Regulated Air Pollutant Emissions (tons per year) [1,2]							
	NO_X	CO	PM_{10}	$PM_{2.5}$ [3]	VOC	SO_2	GHG [4,5]	HAP [6]
Significant	139.6	228.1	11.7	11.7	6.1	50.7	82,822	0.9
Insignificant	0.1	0.4	0.3	0.3	0.3	0.05	217	0.04
Total Emissions	**139.7**	**228.5**	**12.0**	**12.0**	**6.4**	**50.7**	**83,039**	**1.0**

Notes:

[1] Emissions are based on 2022 actual operations and emission factors recorded in source tests, where applicable.

[2] Regulated air pollutant calculations based on AP-42 emission factors, manufacturer data, and mass balances as shown in accompanying spreadsheets.

[3] $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions.

[4] GHG emissions are defined as CO_2e emissions. CO_2e is the summation of CO_2, CH_4, and N_2O, applying the global warming potential for each pollutant.

[5] Per 40 CFR 71.2, GHGs are subject to regulation beginning on July 1, 2011.

[6] See individual emissions unit category HAP emissions calculations for details on methodology and assumptions (electronic copy).

Table D1-2a. Significant Emissions Unit Inventory
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel	Actual Annual	Actual Annual	Rating/
ID	Description	Make/Model	Type	Operating Hours [1]	Operation [1]	Capacity
420a	Generator	Cummins QSK50-G4	Diesel	15.6 hr/yr	1,173 gallons/yr	1,971 hp
421a	Generator	Cummins QSK50-G4	Diesel	16.7 hr/yr		1,971 hp
500	Turbine	Solar Mars 90	Fuel Gas	1,768 hr/yr	607,921.8 Mscf/yr	11,862 kW
501	Turbine	Solar Mars 90	Fuel Gas	7,092 hr/yr	2,438,564.3 Mscf/yr	11,862 kW
503	Production Heater	NATCO	Fuel Gas	8,005 hr/yr	257,828.3 Mscf/yr	34 MMBtu/hr
505	TEG Reboiler	NATCO	Fuel Gas	8,017 hr/yr	7,594.6 Mscf/yr	1.34 MMBtu/hr
507	Flare	Mac Injector 100 Series	Fuel Gas and Produced Gas	8,760 hr/yr	5,554 Mscf/yr	257.9 MMscf/yr
Drill Rig Equipment						
1	Rig Engines	Various	Diesel	0 hr/yr	0 gallons/yr	Various
8	Rig Boilers and Heaters	Various	Diesel	0 hr/yr	0 gallons/yr	Various

Notes:
[1] Actual operations based on operation in calendar year 2022.

Table D1-2b. Insignificant Emissions Unit Inventory
Savant Alaska, LLC - Badami Development Facility

Emission Unit		Fuel	Rating/Capacity	Actual Annual	Actual Annual
ID	Description	Type		Operating Hours [1]	Operation [1]
417	Diesel Tank	NA	15,000 barrels	8,760 hr/yr	N/A
418	Methanol Tank	NA	450 barrels	8,760 hr/yr	N/A
422	Smart Ash 100-A Incinerator	Oily Waste	0.035 tons/hr	730 hr/yr	3.04 ton/yr
502	Therm-Tec-G-12 Incinerator	Propane/Fuel Gas	1.6 MMBtu/hr	N/A	34.6 ton/yr
		Waste	85.0 lb/hr		
607	Indirect Fire Heater	Diesel	1.0 MMBtu/hr	386.8 hr/yr	948.7 gal/yr
608	Indirect Fire Heater	Diesel	1.0 MMBtu/hr	385.8 hr/yr	1,005.1 gal/yr
611	Indirect Fire Heater	Diesel	1.0 MMBtu/hr	171.4 hr/yr	426.6 gal/yr
612	Indirect Fire Heater	Diesel	1.0 MMBtu/hr	649.7 hr/yr	3,569.2 gal/yr
NA	Hot Oil Heater	Diesel	6.0 MMBtu/hr	52 hr/yr	N/A

Notes:
[1] Actual operations based on operation in calendar year 2022.

Table D1-2c. Intermittently Used Oilfield Support Equipment (IUOSE) Inventory
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel	Rating/Capacity	IUOSE	Non-Road	Use (see
Quantity	Description	Make/Model	Type			Engine	below)
1	Grader	Caterpillar 14H	Diesel	215 hp	Yes	Yes	B
1	Loader	Caterpillar 966F	Diesel	218 hp	Yes	Yes	B
1	Excavator	Hitachi XE220LC	Diesel	160 hp	Yes	Yes	B
1	Bobcat	Kubota V2203-E	Diesel	50 hp	Yes	Yes	B
1	Bobcat Skid Steer Loader	Deutz T200	Diesel	72 hp	Yes	Yes	B
1	Loader	Caterpillar 966G	Diesel	439 hp	Yes	Yes	B
1	Ingersoll Rand Pro Pac	Cummins 5.9 SD150D	Diesel	185 hp	Yes	Yes	B
1	Kodiak Snow Blower	Caterpillar C13	Diesel	520 hp	Yes	Yes	B
1	Bulldozer	Caterpillar 3306	Diesel	225 hp	Yes	Yes	B
1	H-Series Guzzler	Caterpillar C10	Diesel	238 hp	Yes	Yes	B
1	Generator (mounted on Guzzler)	Yanmar 3Tne	Diesel	13 hp	Yes	Yes	B
1	Fuel Truck	Detroit 6067E	Diesel	350 hp	Yes	Yes	B
1	Dump Truck	Caterpillar 406	Diesel	380 hp	Yes	Yes	B
1	Box Truck	Caterpillar 3126	Diesel	230 hp	Yes	Yes	B
1	Tucker Snow Vehicle	Cummins QSB3.9	Diesel	130 hp	Yes	Yes	B
1	Argo 750 HDI	Kohler LH 775	Gasoline	31 hp	Yes	Yes	B
1	Genie Zoom Boom	Perkins 1104C-44T	Diesel	99 hp	Yes	Yes	A&B
1	Air Compressor	Deutz TD20111l04w	Diesel	63 hp	Yes	Yes	A&B
1	Triplex Pump	Cummins B3.3	Diesel	85 hp	Yes	Yes	A&B
1	Hot Oil Generator	Kubota D1105	Diesel	21 hp	Yes	Yes	A&B
1	Hot Oil Tractor/Pump	Cummins N-14	Diesel	330 hp	Yes	Yes	A&B
1	Generator (mounted on Guzzler)	Cummins 4BTA 5.9	Diesel	67 hp	Yes	Yes	A&B
1	EU BAD 022 - Hot Oil Heater	Webster Cyclonetic JB2-50-YB110-MR	Diesel	6 MMBtu/hr	Yes	No	A&B
1	EU 603a - Air Compressor	Sullair 200HDPQAi4	Diesel	55 hp	Yes	Yes	A&B
1	EU 600 - Crane	Grove RT635C	Diesel	215 hp	Yes	Yes	A&B
1	EU BAD 034a - Manlift	Perkins 804C	Diesel	63 hp	Yes	Yes	A&B
1	EU 604 - Welder	Bobcat 250	Diesel	38 hp	Yes	Yes	A&B
1	EU BAD 036 - Portable Welder Engine	Miller Bobcat MD#907039	Diesel	20 hp	Yes	Yes	A&B
1	LED Light Plant	Perkins 403D	Diesel	11 hp	Yes	Yes	C
2	EU 601/602 - Light Plants	Unknown	Diesel	12.1 hp	Yes	Yes	C
4	ES700 Indirect Fire Heater Motor (used with EU 607608/611/612)	Kubota D1105	Diesel	13 hp	Yes	Yes	C
1	EU 607 (BAD 028) - Indirect Fire Heater	Tioga ES700 - Heater #1	Diesel	1 MMBtu/hr	Yes	No	C
1	EU 608 (BAD 029) - Indirect Fire Heater	Tioga ES700 - Heater #2	Diesel	1 MMBtu/hr	Yes	No	C
1	EU 611 (BAD 030) - Indirect Fire Heater	Tioga ES700 - Heater #3	Diesel	1 MMBtu/hr	Yes	No	C
1	EU 612 (BAD 031) - Indirect Fire Heater	Tioga ES700 - Heater #4	Diesel	1 MMBtu/hr	Yes	No	C
10	Rig Light Plant	Unknown	Diesel	16 hp, each	Yes	Yes	D
1	Frac Engine	Caterpillar 3512	Diesel	1,800 hp	Yes	Yes	D
1	Cement Pump Van Onan	Unknown	Diesel	325 hp	Yes	Yes	D
1	Cement Batch Mixer Onan	Unknown	Diesel	34 hp	Yes	Yes	D
1	Slickline Generator	Unknown	Diesel	31 hp	Yes	Yes	D
1	Slickline Powerpack	John Deere	Diesel	120 hp	Yes	Yes	D
1	E-Line Logger	Unknown	Diesel	310 hp	Yes	Yes	D
1	E-Line Grease Skid	Unknown	Diesel	90 hp	Yes	Yes	D
1	E-Line Spare Generator	Unknown	Diesel	50 hp	Yes	Yes	D
1	CTU Onan	Unknown	Diesel	34 hp	Yes	Yes	D
1	CTU Power Pack	Unknown	Diesel	425 hp	Yes	Yes	D
1	CTU Tractor/Pump	Unknown	Diesel	450 hp	Yes	Yes	D

Notes:

A - Oil Well Servicing and Maintenance

B - General Oilfield Maintenance for Pipelines, Roads, and Other Existing Infrastructure.

C - Oil Well Servicing and General Oilfield Maintenance for Pipelines, Roads, and Other Existing Infrastructure. Units are in storage and used in winter months as needed.

D - Oil Well Servicing and Maintenance, contractor equipment not permanently onsite (ratings are estimated).

Table D1-3. Actual Emissions (After Controls/Limitations) - Oxides of Nitrogen (NO_X)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel	Factor	Emission	Actual Annual	Actual Annual
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions [1]
Significant Emission Units							
420a	Generator	1,971 hp	Diesel	Source Test	0.414 lb/gal	1,173 gallons/yr	0.2 tpy
421a	Generator	1,971 hp	Diesel	Source Test			
500	Turbine	11,862 kW	Fuel Gas	AQ0417TVP03, Cond. 17.1b	28.4 lb/hr	1,768 hr/yr	25.1 tpy
501	Turbine	11,862 kW	Fuel Gas	AQ0417TVP03, Cond. 17.1b	28.4 lb/hr	7,092 hr/yr	100.7 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	AQ0417TVP03, Cond. 17.1b	0.095 lb/MMBtu	8,005 hr/yr	12.9 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	AQ0417TVP03, Cond. 17.1b	0.08 lb/MMBtu	8,017 hr/yr	0.4 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	AP-42 Table 13.5-1	0.068 lb/MMBtu	5,554 Mscf/yr	0.2 tpy
Drill Rig Equipment							
1	Rig Engines	Various	Diesel	AP-42 Table 3.4-1	0.024 lb/hp-hr	0 gallons	0 tpy
8	Rig Boilers and Heaters	Various	Diesel	AP-42 Table 1.3-1	20 $lb/10^3$ gal	0 gallons	0 tpy
Significant Emission Units - Estimated Actual Emissions - NO_X							**139.6 tpy**
Insignificant Emission Units							
417	Diesel Tank	15,000 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
418	Methanol Tank	450 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	AP-42, Table 2.1-12	2 lb/ton	3.0 ton/yr	0.003 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	AP-42, Table 2.1-12	2 lb/ton	34.6 ton/yr	0.03 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	20 $lb/10^3$ gal	948.7 gal/yr	0.009 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	20 $lb/10^3$ gal	1,005.1 gal/yr	0.01 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	20 $lb/10^3$ gal	426.6 gal/yr	0.004 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	20 $lb/10^3$ gal	3,569.2 gal/yr	0.04 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	20 $lb/10^3$ gal	52 hr/yr	0.02 tpy
Insignificant Emission Units - Estimated Actual Emissions - NO_X							**0.1 tpy**
Total Estimated Actual Emissions - NO_X							**139.7 tpy**

Notes:

[1] Parameters and Conversions:

Gas HHV 2022 Average	1,056 Btu/scf
Diesel Heat Content (AP-42, Appendix A)	137,000 Btu/gal

Table D1-4. Actual Emissions (After Controls/Limitations) - Carbon Monoxide (CO)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel	Factor	Emission	Actual Annual	Actual Annual
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions [1]
Significant Emission Units							
420a	Generator	1,971 hp	Diesel	AQ0417TVP03, Cond. 36.1	3.5 g/kW-hr	15.6 hr/yr	0.09 tpy
421a	Generator	1,971 hp	Diesel	AQ0417TVP03, Cond. 36.1	3.5 g/kW-hr	16.7 hr/yr	0.09 tpy
500	Turbine	11,862 kW	Fuel Gas	AQ0417TVP03, Table B	Varies [2]	1,768 hr/yr	12.0 tpy
501	Turbine	11,862 kW	Fuel Gas	AQ0417TVP03, Table B	Varies [2]	7,092 hr/yr	206.8 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	AQ0417TVP03, Cond. 17.2a	3.4 lb/hr	8,005 hr/yr	7.4 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	AQ0417TVP03, Cond. 17.2a	0.15 lb/MMBtu	8,017 hr/yr	0.8 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	AP-42, Table 13.5-2	0.31 lb/MMBtu	5,554 Mscf	0.9 tpy
Drill Rig Equipment							
1	Rig Engines	Various	Diesel	AP-42, Table 3.4-1	0.0055 lb/hp-hr	0 gallons	0 tpy
8	Rig Boilers and Heaters	Various	Diesel	AP-42, Table 1.3-1	5 $lb/10^3$ gal	0 gallons	0 tpy
Significant Emission Units - Estimated Actual Emissions - CO							**228.1 tpy**
Insignificant Emission Units							
417	Diesel Tank	15,000 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
418	Methanol Tank	450 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	AP-42, Table 2.1-12	20 lb/ton	3.0 ton/yr	0.03 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	AP-42, Table 2.1-12	20 lb/ton	34.6 ton/yr	0.3 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	5 $lb/10^3$ gal	948.7 gal/yr	0.002 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	5 $lb/10^3$ gal	1,005.1 gal/yr	0.003 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	5 $lb/10^3$ gal	426.6 gal/yr	0.001 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	5 $lb/10^3$ gal	3,569.2 gal/yr	0.009 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	5 $lb/10^3$ gal	52 hr/yr	0.006 tpy
Insignificant Emission Units - Estimated Actual Emissions - CO							**0.4 tpy**
Total Estimated Actual Emissions - CO							**228.5 tpy**

Notes:

[1] Parameters and Conversions:

Gas HHV 2022 Average	1,056 Btu/scf
Diesel Heat Content (AP-42, Appendix A)	137,000 Btu/gal

[2] Calculations are performed using emission factors based on 2022 actual load and temperature.

Table D1-5. Actual Emissions (After Controls/Limitations) - Particulate Matter Less Than 10 Microns (PM_{10})
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Factor Reference	Emission Factor	Actual Annual Operation	Actual Annual Emissions [1]
ID	Description	Rating/Capacity					
Significant Emission Units							
420a	Generator	1,971 hp	Diesel	AQ0417TVP03, Cond. 36.1	0.20 g/kW-hr	15.6 hr/yr	0.005 tpy
421a	Generator	1,971 hp	Diesel	AQ0417TVP03, Cond. 36.1	0.20 g/kW-hr	16.7 hr/yr	0.005 tpy
500	Turbine	11,862 kW	Fuel Gas	AP-42, Table 3.1-1	0.0066 lb/MMBtu	607,921.8 Mscf/yr	2.1 tpy
501	Turbine	11,862 kW	Fuel Gas	AP-42, Table 3.1-1	0.0066 lb/MMBtu	2,438,564.3 Mscf/yr	8.5 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	AP-42, Table 1.4-2	7.6 lb/MMscf	8,005 hr/yr	1.0 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	AP-42, Table 1.4-2	7.6 lb/MMscf	8,017 hr/yr	0.04 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	AP-42, Table 13.5-1	40 µg/L	5,554 Mscf	0.06 tpy
Drill Rig Equipment							
1	Rig Engines	Various	Diesel	AP-42, Table 3.4-1	0.0007 lb/hp-hr	0 gallons	0 tpy
8	Rig Boilers and Heaters	Various	Diesel	AP-42, Table 1.3-1 and 1.3-2	3.3 $lb/10^3$ gal	0 gallons	0 tpy
						Significant Emission Units - Estimated Actual Emissions - PM_{10}	**11.7 tpy**
Insignificant Emission Units							
417	Diesel Tank	15,000 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
418	Methanol Tank	450 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	Source test from operating instructions	0.08 lb/hr	3.0 ton/yr	1.2.E-04 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	AP-42, Table 2.1-12	15.0 lb/ton	34.6 ton/yr	0.3 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1 and 1.3-2	3.3 $lb/10^3$ gal	948.7 gal/yr	0.002 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1 and 1.3-2	3.3 $lb/10^3$ gal	1,005.1 gal/yr	0.002 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1 and 1.3-2	3.3 $lb/10^3$ gal	426.6 gal/yr	7.0E-04 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1 and 1.3-2	3.3 $lb/10^3$ gal	3,569.2 gal/yr	0.006 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1 and 1.3-2	3.3 $lb/10^3$ gal	52 hr/yr	0.004 tpy
						Insignificant Emission Units - Estimated Actual Emissions - PM_{10}	**0.3 tpy**
						Total Estimated Actual Emissions - PM_{10}	**12.0 tpy**

Notes:

[1] Parameters and Conversions:

Gas HHV 2022 Average	1,056	Btu/scf
F-Factor (40 CFR 60, Method 19)	8710	dscf/MMBtu
Diesel Heat Content (AP-42, Appendix A)	137,000	Btu/gal

Table D1-6a. Actual Emissions (After Controls/Limitations) - Volatile Organic Compounds (VOCs)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Factor Reference	Emission Factor	Actual Annual Operation	Actual Annual Emissions [1]
ID	Description	Rating/Capacity					
Significant Emission Units							
420a	Generator	1,971 hp	Diesel	Vendor Data	0.14 g/hp-hr	15.6 hr/yr	0.005 tpy
421a	Generator	1,971 hp	Diesel	Vendor Data	0.14 g/hp-hr	16.7 hr/yr	0.005 tpy
500	Turbine	11,862 kW	Fuel Gas	AP-42, Table 3.1-2a	0.0021 lb/MMBtu	607,921.8 Mscf/yr	0.7 tpy
501	Turbine	11,862 kW	Fuel Gas	AP-42, Table 3.1-2a	0.0021 lb/MMBtu	2,438,564.3 Mscf/yr	2.7 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	AP-42, Table 1.4-2	5.5 lb/MMscf	257,828.3 Mscf/yr	0.7 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	AP-42, Table 1.4-2	5.5 lb/MMscf	7,594.6 Mscf/yr	0.02 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	AP-42 Table 13.5-2	0.66 lb/MMBtu	5,554.0 Mscf	1.9 tpy
Drill Rig Equipment							
1	Rig Engines	Various	Diesel	AP-42, Table 3.4-1	0.0007 lb/hp-hr	0 gallons	0 tpy
8	Rig Boilers and Heaters	Various	Diesel	AP-42, Table 1.3-3	0.34 $lb/10^3$ gal	0 gallons	0 tpy
Significant Emission Units - Estimated Actual Emissions - VOC							**6.1 tpy**
Insignificant Emission Units							
417	Diesel Tank	15,000 barrels	NA	See Table D1-6b	NA	8,760 hr/yr	0.00 tpy
418	Methanol Tank	450 barrels	NA	See Table D1-6b	NA	8,760 hr/yr	0.1 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	AP-42, Table 2.1-12	15 lb/ton	3.0 ton/yr	0.02 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	AP-42, Table 2.1-12	15 lb/ton	34.6 ton/yr	0.3 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-3	0.34 $lb/10^3$ gal	948.7 gal/yr	1.6E-04 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-3	0.34 $lb/10^3$ gal	1,005.1 gal/yr	1.7E-04 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-3	0.34 $lb/10^3$ gal	426.6 gal/yr	7.3E-05 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-3	0.34 $lb/10^3$ gal	3,569.2 gal/yr	6.1E-04 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	AP-42, Table 1.3-3	0.34 $lb/10^3$ gal	52 hr/yr	3.9E-04 tpy
Insignificant Emission Units - Estimated Actual Emissions - VOC							**0.3 tpy**
Total Estimated Actual Emissions - VOC							**6.4 tpy**

Notes:

[1] Parameters and Conversions:

Gas HHV 2022 Average	1,056 Btu/scf
Diesel Heat Content (AP-42, Appendix A)	137,000 Btu/gal

Table D1-6b. Actual Emissions (After Controls/Limitations) - Volatile Organic Compounds (VOCs)

Savant Alaska, LLC - Badami Development Facility

Parameter	Factor Reference	Emissions Unit ID	
		417	418
Orientation	NA	Vertical	Horizontal
Contents	NA	ULSD	Methanol
Diameter (ft), D	NA	67	9.3
Effective Diameter (ft), D_E	AP-42, Section 7.1, Equation 1-14	---	21.2
Height (ft), H_S	NA	24	---
Effective Height (ft), H_E	AP-42, Section 7.1, Equation 1-15	---	7.3
Length (ft), L	NA	---	38
Color	NA	White	White
Maximum Liquid Height (ft), H_L	NA	23	---
Capacity (gal)	NA	630,000	18,900
Throughput (gal/yr) [1]	NA	29,597	32,091
Turnovers	NA	0.05	1.7
Paint Condition	NA	New	New
Standing Loss (L_S) Calculations [2,3]			
K_E	AP-42, Section 7.1, Equation 1-12	0.020	0.020
H_{VO} (ft)	AP-42, Section 7.1, Equation 1-16	1.70	3.7
H_{RO} (ft)	AP-42, Section 7.1, Equation 1-17	0.70	0.10
K_S	AP-42, Section 7.1, Equation 1-21	0.999	0.778
T_{AA} (^oR)	AP-42, Section 7.1, Equation 1-30	470.30	470.30
T_B (^oR)	AP-42, Section 7.1, Equation 1-31	470.73	470.73
T_V (^oR) - uninsulated	AP-42, Section 7.1, Equation 1-33	471.71	471.71
W_V (lb/ft^3)	AP-42, Section 7.1, Equation 1-22	1.54E-04	9.34E-03
L_S (lb/yr)	AP-42, Section 7.1, Equation 1-4	6.8	69.3
Working Loss (L_W) Calculations [3]			
Q (bbl/yr)	NA	705	764
V_Q (ft^3)	AP-42, Section 7.1, Equation 1-39	3,956	4,289
K_N [4]	AP-42, Section 7.1, Equation 1-35	1	1
L_W (lb/yr)	AP-42, Section 7.1, Equation 1-35	0.6	40.1
TOTAL VOCs L_T (tpy)	**AP-42, Section 7.1, Equation 1-1**	**0.004**	**0.05**

Notes:

[1] Tanks are filled with submerged loading. Actual throughput from 2022.

[2] Meteorological Inputs (Deadhorse, AK):

	T_{AX} =	16.6	^oF
		476.3	^oR
AP-42, Section 7.1, Table 7.1-6	T_{AN} =	4.6	^oF
		464.3	^oR
AP-42, Section 7.1, Table 7.1-7	α =	0.17	White, New
	I =	838	Btu/ft^2-d

[3] Constants: From the 1995 version of AP-42

AP-42, Section 7.1, Table 7.1-2 (diesel/distilate)			
AP-42, Section 7.1, Table 7.1-2	M_V (diesel)=	130	lb/lb-mol
AP-42, Section 7.1, Note below equation 1-37	P_{VA} (diesel)=	0.006	psi
AP-42, Section 7.1, Note below equation 1-37	K_P (diesel)=	1	
	K_B =	1	
AP-42, Section 7.1, Table 7.1-2 (methanol)			
AP-42, Section 7.1, Table 7.1-3	M_V (MeOH)=	32.04	lb/lb-mol
AP-42, Section 7.1, Note below equation 1-37	P_{VA} (MeOH)=	1.476	psi
AP-42, Section 7.1, Note below equation 1-37	K_P (MeOH)=	1	
	K_B =	1	

[4] K_N is equal to 1 for 36 or less turnovers per year

Table D1-7. Actual Emissions (After Controls/Limitations) - Sulfur Dioxide (SO_2)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Actual Fuel [1] Sulfur Content	Factor Reference	Emission Factor [2,3]	Actual Annual Operation	Actual Annual Emissions [3]
ID	Description	Rating/Capacity						
Significant Emission Units								
420a	Generator	1,971 hp	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	1,173.0 gallons/yr	1.2E-04 tpy
421a	Generator	1,971 hp	Diesel					
500	Turbine	11,862 kW	Fuel Gas	Varies	Actual Monthly H_2S Sample	Varies	607,921.8 Mscf/yr	10.2 tpy
501	Turbine	11,862 kW	Fuel Gas	Varies	Actual Monthly H_2S Sample	Varies	2,438,564.3 Mscf/yr	36.4 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	Varies	Actual Monthly H_2S Sample	Varies	257,828.3 Mscf/yr	3.9 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	Varies	Actual Monthly H_2S Sample	Varies	7,594.6 Mscf/yr	0.1 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	Varies	Actual Monthly H_2S Sample	Varies	5,554.0 Mscf/yr	0.01 tpy
Drill Rig Equipment								
1	Rig Engines	Various	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	0 gallons	0 tpy
8	Rig Boilers and Heaters	Various	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	0 gallons	0 tpy
Significant Emission Units - Estimated Actual Emissions - SO_2								**50.7 tpy**
Insignificant Emission Units								
417	Diesel Tank	15,000 barrels	NA	NA	NA	NA	8,760 hr/yr	0 tpy
418	Methanol Tank	450 barrels	NA	NA	NA	NA	8,760 hr/yr	0 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	NA	AP-42, Table 2.1-12	2.5 lb/ton	3.0 ton/yr	3.8E-03 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	NA	AP-42, Table 2.1-12	2.5 lb/ton	34.6 ton/yr	0.04 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	948.7 gal/yr	1.0E-04 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	1,005.1 gal/yr	1.1E-04 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	426.6 gal/yr	4.5E-05 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	3,569.2 gal/yr	3.8E-04 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	52 hr/yr	5.5E-06 tpy
Insignificant Emission Units - Estimated Actual Emissions - SO_2								**0.05 tpy**
Total Estimated Actual Emissions - SO_2								**50.7 tpy**

Notes:

[1] Diesel used at the facility is ultra low sulfur diesel (ULSD) with a maximum sulfur of 15 ppmw. Fuel gas sulfur content based on the monthly maximum actual H2S analyses from 2022.

[2] Mass balance:

For fuel gas, the SO_2 emission factor is calculated based on the natural gas sulfur content.

ppmv H_2S = scf H_2S per MMscf fuel gas

Molar ratio: 1 mol H_2S = 1 mol S = 1 mol SO_2

Sulfur content of Natural Gas = 0.75 ppmv H_2S = 0.75 scf H_2S/MMscf fuel

SO_2 Emission Factor, lb/MMscf = (scf H_2S/MMscf fuel) x (64 lb SO_2/1mol S) / (379.9 scf/mol at STP)

For diesel units, the SO_2 emission factor is calculated based on the sulfur content in diesel fuel

Molar mass ratio is 32 lb S/mol : 64 lb SO_2/mol; Stoichiometry: 1 mol S = 1 mol SO_2

SO_2 Emission Factor, lb/gal = (Molar mass ratio, 2 lb SO_2: 1 lb S) x (weight % S in fuel) x (density of fuel, lb/gal) / 100%

[3] Conversions and parameters.

Diesel density (AP-42, Appendix A)	7.05	lb/gal
Engine heat rate (AP-42, Section 3.3)	7,000	Btu/hp-hr
Diesel Heat Content (AP-42, Appendix	137,000	Btu/gal

Table D1-8. Actual Emissions (After Controls/Limitations) - Greenhouse Gas Carbon Dioxide Equivalent (CO_2e)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Actual Annual Greenhouse Gas Emissions (tpy)				
ID	Description	Rating/Capacity		CO_2	CH_4	N_2O	GHG Mass	GHG CO_2e
Significant Emission Units								
420a	Generator	1,971 hp	Diesel	13	5.3E-04	1.1E-04	13	13
421a	Generator	1,971 hp	Diesel					
500	Turbine	11,862 kW	Fuel Gas	13,137	0.25	0.025	13,137	13,151
501	Turbine	11,862 kW	Fuel Gas	52,697	0.99	0.099	52,698	52,751
503	Production Heater	34 MMBtu/hr	Fuel Gas	15,919	0.30	0.030	15,919	15,935
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	628	0.01	0.001	628	629
507	Flare	258 MMscf/yr	Fuel Gas and Produced Gas	343	0.006	0.0006	343	343
Drill Rig Equipment								
1	Rig Engines	Various	Diesel	0	0	0	0	0
8	Rig Boilers and Heaters	Various	Diesel	0	0	0	0	0
Significant Emission Units - Estimated Actual Emissions - Greenhouse Gases							**82,739**	**82,822**
Insignificant Emission Units								
417	Diesel Tank	15,000 barrels	NA	0	0	0	0	0
418	Methanol Tank	450 barrels	NA	0	0	0	0	0
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	25	0.009	0.001	25	26
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	34	0.01	0.002	34	35
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	32	0.001	2.6E-04	32	32
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	31	0.001	2.6E-04	31	32
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	14	5.7E-04	1.1E-04	14	14
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	53	0.002	4.3E-04	53	53
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	25.4	1.0E-03	2.1E-04	25.4	25.5
Insignificant Emission Units - Estimated Actual Emissions - Greenhouse Gases							**215**	**217**
Total Estimated Actual Emissions - Greenhouse Gases							**82,954**	**83,039**

Table D1-9. Actual Emissions (After Controls/Limitations) - Carbon Dioxide (CO_2)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel	Factor	Emission	Actual Annual	Actual Annual
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions [1]
Significant Emission Units							
420a	Generator	1,971 hp	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	1,173 gallons/yr	13 tpy
421a	Generator	1,971 hp	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu		
500	Turbine	11,862 kW	Fuel Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	1,768 hr/yr	13,137 tpy
501	Turbine	11,862 kW	Fuel Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	7,092 hr/yr	52,697 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,005 hr/yr	15,919 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,017 hr/yr	628 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	5,554 Mscf	343 tpy
Drill Rig Equipment							
1	Rig Engines	Various	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	0 gallons	0 tpy
8	Rig Boilers and Heaters	Various	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	0 gallons	0 tpy
						Significant Emission Units - Estimated Actual Emissions - CO_2	**82,737 tpy**
Insignificant Emission Units							
417	Diesel Tank	15,000 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
418	Methanol Tank	450 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	40 CFR 98, Table C-1	90.7 kg/MMBtu	730 hr/yr	25 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	40 CFR 98, Table C-1	90.7 kg/MMBtu	813 hr/yr	34 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	387 hr/yr	32 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	386 hr/yr	31 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	171 hr/yr	14 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	650 hr/yr	53 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	52 hr/yr	25 tpy
						Insignificant Emission Units - Estimated Actual Emissions - CO_2	**215 tpy**
						Total Estimated Actual Emissions- CO_2	**82,952 tpy**

Notes:

[1] Conversions and parameters.

Diesel Heat Content (AP-42, Appendix A)	137,000	Btu/gal
Vendor turbine Heat Rate	10,710	Btu/kW-hr
Gas HHV 2022 Average	1,056	Btu/scf
Solid waste heat value (40 CFR 98, Table C-1)	9.95	MMBtu/ton
Engine heat rate (AP-42, Section 3.3)	7,000	Btu/hp-hr

Table D1-10. Actual Emissions (After Controls/Limitations) - Methane (CH_4)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Factor Reference	Emission Factor	Actual Annual Operation	Actual Annual Emissions [1]
ID	Description	Rating/Capacity					
Significant Emission Units							
420a	Generator	1,971 hp	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	1,173 gallons/yr	5.3E-04 tpy
421a	Generator	1,971 hp	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu		
500	Turbine	11,862 kW	Fuel Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	1,768 hr/yr	0.2 tpy
501	Turbine	11,862 kW	Fuel Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	7,092 hr/yr	1.0 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,005 hr/yr	0.3 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,017 hr/yr	0.01 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	5,554 Mscf	0.006 tpy
Drill Rig Equipment							
1	Rig Engines	Various	Diesel	45 CFR 98, Table C-2	0.003 kg/MMBtu	0 gallons	0 tpy
8	Rig Boilers and Heaters	Various	Diesel	45 CFR 98, Table C-2	0.003 kg/MMBtu	0 gallons	0 tpy
Significant Emission Units - Estimated Actual Emissions - CH_4							**1.6 tpy**
Insignificant Emission Units							
417	Diesel Tank	15,000 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
418	Methanol Tank	450 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	40 CFR 98, Table C-2	0.032 kg/MMBtu	730 hr/yr	0.009 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	40 CFR 98, Table C-2	0.032 kg/MMBtu	813 hr/yr	0.01 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	387 hr/yr	0.001 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	386 hr/yr	0.001 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	171 hr/yr	5.7E-04 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	650 hr/yr	0.002 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	52 hr/yr	0.001 tpy
Insignificant Emission Units - Estimated Actual Emissions - CH_4							**0.03 tpy**
Total Estimated Actual Emissions - CH_4							**1.6 tpy**

Notes:

[1] Conversions and parameters.

Diesel Heat Content (AP-42, Appendix A)	137,000 Btu/gal
Vendor turbine Heat Rate	10,710 Btu/kW-hr
Gas HHV 2022 Average	1,040 Btu/scf
Solid waste heat value (40 CFR 98, Table C-1)	9.95 MMBtu/ton
Engine heat rate (AP-42, Section 3.3)	7,000 Btu/hp-hr

Table D1-11. Actual Emissions (After Controls/Limitations) - Nitrous Oxide (N_2O)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Factor Reference	Emission Factor	Actual Annual Operation	Actual Annual Emissions [1]
ID	Description	Rating/Capacity					
Significant Emission Units							
420a	Generator	1,971 hp	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	1,173 gallons/yr	1.1E-04 tpy
421a	Generator	1,971 hp	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu		
500	Turbine	11,862 kW	Fuel Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	1,768 hr/yr	0.02 tpy
501	Turbine	11,862 kW	Fuel Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	7,092 hr/yr	0.1 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,005 hr/yr	0.03 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,017 hr/yr	0.001 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	5,554 Mscf	6.4E-04 tpy
Drill Rig Equipment							
1	Rig Engines	Various	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	0 gallons	0 tpy
8	Rig Boilers and Heaters	Various	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	0 gallons	0 tpy
Significant Emission Units - Estimated Actual Emissions - N_2O							**0.2 tpy**
Insignificant Emission Units							
417	Diesel Tank	15,000 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
418	Methanol Tank	450 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	40 CFR 98, Table C-2	0.0042 kg/MMBtu	730 hr/yr	0.001 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	40 CFR 98, Table C-2	0.0042 kg/MMBtu	813 hr/yr	0.002 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	387 hr/yr	2.6E-04 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	386 hr/yr	2.6E-04 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	171 hr/yr	1.1E-04 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	650 hr/yr	4.3E-04 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	52 hr/yr	2.1E-04 tpy
Insignificant Emission Units - Estimated Actual Emissions - N_2O							**0.004 tpy**
Total Estimated Actual Emissions - N_2O							**0.2 tpy**

Notes:

[1] Conversions and parameters.

Diesel Heat Content (AP-42, Appendix A)	137,000 Btu/gal
Vendor turbine Heat Rate	10,710 Btu/kW-hr
Gas HHV 2022 Average	1,040 Btu/scf
Solid waste heat value (40 CFR 98, Table C-1)	9.95 MMBtu/ton
Engine heat rate (AP-42, Section 3.3)	7,000 Btu/hp-hr

Table D1-12. Actual Emissions (After Controls/Limitations) - Hazardous Air Pollutant (HAP)
Savant Alaska, LLC - Badami Development Facility

Hazardous Air Pollutant	Diesel Engines >600 hp	Natural Gas Turbines	Natural Gas Boilers/Heaters	Flares	Diesel Boilers/Heaters	Insignificant Incinerators	Insignificant Diesel Heaters	Total HAP Emissions[1]
Acetaldehyde	2.02E-06	2.25E-02	----	1.19E-04	----	----	----	**2.26E-02**
Acrolein	6.33E-07	3.60E-03	----	2.78E-05	----	----	----	**3.63E-03**
Benzene	6.24E-05	6.75E-03	2.81E-04	4.42E-04	0.00E+00	----	1.49E-06	**7.54E-03**
1,3-Butadiene	----	2.42E-04	----	----	----	----	----	**2.42E-04**
1,4-Dichlorobenzene(p)	----	----	1.61E-04	----	----	----	----	**1.61E-04**
Ethyl benzene	----	1.80E-02	----	4.01E-03	0.00E+00	----	4.42E-07	**2.20E-02**
Formaldehyde	6.3E-06	4.0E-01	1.0E-02	3.2E-03	0	----	2.3E-04	**4.13E-01**
N-Hexane	----	----	2.4E-01	2.9E-02	----	----	----	**2.70E-01**
Hydrochloric acid	----	----	----	----	----	4.04E-02	----	**4.04E-02**
Polycyclic Organic Matter (POM)	1.70E-05	1.24E-03	9.57E-05	3.89E-05	0.00E+00	----	2.30E-05	**1.41E-03**
Acenaphthene	3.76E-07	----	2.41E-06	----	0.00E+00	----	1.76E-09	**2.79E-06**
Acenaphthylene	7.42E-07	----	2.41E-07	----	0.00E+00	----	1.47E-07	**1.13E-06**
Anthracene	9.88E-08	----	3.21E-07	----	0.00E+00	----	8.49E-09	**4.29E-07**
Benzo(a)anthracene	5.00E-08	----	2.41E-07	----	0.00E+00	----	2.79E-08	**3.19E-07**
Benzo(a)pyrene	----	----	1.61E-07	----	----	----	----	**1.61E-07**
Benzo(b)fluoranthene	8.92E-08	----	2.41E-07	----	----	----	----	**3.30E-07**
Benzo(g,h,i)perylene	----	----	1.61E-07	----	----	----	----	**1.61E-07**
Benzo(g,h,l)perylene	----	----	----	----	0.00E+00	----	1.57E-08	**1.57E-08**
Benzo(k)fluoranthene	----	----	2.41E-07	----	----	----	----	**2.41E-07**
Chrysene	----	----	2.41E-07	----	0.00E+00	----	1.66E-08	**2.58E-07**
Dibenz(a,h)anthracene	----	----	1.61E-07	----	0.00E+00	----	1.16E-08	**1.72E-07**
Fluorene	----	----	3.75E-07	----	0.00E+00	----	3.11E-08	**4.06E-07**
Fluoranthene	----	----	4.02E-07	----	0.00E+00	----	3.37E-08	**4.36E-07**
Indeno(1,2,3-cd)pyrene	----	----	----	----	0.00E+00	----	1.49E-08	**1.49E-08**
2-Methylnaphthalene	----	----	3.21E-06	----	----	----	----	**3.21E-06**
Naphthalene	----	7.32E-04	8.17E-05	3.05E-05	0.00E+00	----	7.86E-06	**8.52E-04**
Phenanthrene	----	----	2.28E-06	----	0.00E+00	----	7.30E-08	**2.35E-06**
Pyrene	----	----	6.70E-07	----	0.00E+00	----	2.96E-08	**6.99E-07**
Propylene oxide	----	1.63E-02	----	----	----	----	----	**1.63E-02**
Toluene	2.26E-05	7.32E-02	4.55E-04	1.61E-04	0.00E+00	----	4.31E-05	**7.38E-02**
1,1,1-Trichloroethane	----	----	----	----	0.00E+00	----	1.64E-06	**1.64E-06**
Xylenes	1.55E-05	3.60E-02	----	8.05E-05	0.00E+00	----	7.58E-07	**3.61E-02**
Arsenic Compounds	----	----	----	----	0.00E+00	1.26E-05	3.81E-06	**1.64E-05**

Table D1-12. Actual Emissions (After Controls/Limitations) - Hazardous Air Pollutant (HAP)
Savant Alaska, LLC - Badami Development Facility

Hazardous Air Pollutant	Diesel Engines >600 hp	Natural Gas Turbines	Natural Gas Boilers/Heaters	Flares	Diesel Boilers/Heaters	Insignificant Incinerators	Insignificant Diesel Heaters	Total HAP Emissions[1]
Beryllium Compounds	----	----	----	----	0.00E+00	----	2.86E-06	**2.86E-06**
Cadmium Compounds	----	----	----	----	0.00E+00	4.53E-05	2.86E-06	**4.82E-05**
Chromium Compounds	----	----	----	----	0.00E+00	6.22E-05	2.86E-06	**6.51E-05**
Lead Compounds	----	----	7.07E-02	----	0.00E+00	----	8.58E-06	**7.07E-02**
Manganese Compounds	----	----	----	----	0.00E+00	----	5.72E-06	**5.72E-06**
Mercury Compounds	----	----	----	----	0.00E+00	1.05E-04	2.86E-06	**1.08E-04**
Nickel Compounds	----	----	----	----	0.00E+00	1.04E-04	2.86E-06	**1.07E-04**
Selenium Compounds	----	----	----	----	0.00E+00	----	1.43E-05	**1.43E-05**
Dioxins/Furans	----	----	----	----	----	5.53E-08	----	**5.53E-08**
Total HAPs - Maximum Individual HAP	**6.2E-05**	**0.4**	**0.2**	**0.03**	**0**	**0.04**	**2.3E-04**	**0.4**
Total VOC HAP Emissions	**1.3E-04**	**0.6**	**0.3**	**0.04**	**0**	**0**	**3.0E-04**	**0.9**
Total HAPs Emissions	**1.3E-04**	**0.6**	**0.3**	**0.04**	**0**	**0.04**	**3.5E-04**	**1.0**

Notes:
[1] See individual emissions unit category emissions calculations for details on methodology and assumptions in the electronic copy.

Table D1-13. Actual Emissions (After Controls/Limitations) - Hazardous Air Pollutant (HAP)
Diesel Engines Greater Than or Equal to 600 Horsepower

Maximum Total Heat Input: 160.7 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**Emission Factor [2]**	**Estimated Emissions**
75-07-0	Acetaldehyde	2.52E-05 lb/MMBtu	2.02E-06 tpy
107-02-8	Acrolein	7.88E-06 lb/MMBtu	6.33E-07 tpy
71-43-2	Benzene	7.76E-04 lb/MMBtu	6.24E-05 tpy
50-00-0	Formaldehyde	7.89E-05 lb/MMBtu	6.34E-06 tpy
108-88-3	Toluene	2.81E-04 lb/MMBtu	2.26E-05 tpy
1330-20-7	Xylenes	1.93E-04 lb/MMBtu	1.55E-05 tpy
N/A	Polycyclic Organic Matter (POM)	2.12E-04 lb/MMBtu	1.70E-05 tpy
	Polycyclic aromatic compounds(PAH)		
208-96-8	Acenaphthene	4.68E-06 lb/MMBtu	3.76E-07 tpy
83-32-9	Acenaphthylene	9.23E-06 lb/MMBtu	7.42E-07 tpy
120-12-7	Anthracene	1.23E-06 lb/MMBtu	9.88E-08 tpy
56-55-3	Benzo(a)anthracene	6.22E-07 lb/MMBtu	5.00E-08 tpy
205-99-2	Benzo(b)fluoranthene	1.11E-06 lb/MMBtu	8.92E-08 tpy
207-08-9	Benzo(k)fluoranthene	2.18E-07 lb/MMBtu	1.75E-08 tpy
50-32-8	Benzo(a)pyrene	2.57E-07 lb/MMBtu	2.07E-08 tpy
191-24-2	Benzo(g,h,l)perylene	5.56E-07 lb/MMBtu	4.47E-08 tpy
218-01-9	Chrysene	1.53E-06 lb/MMBtu	1.23E-07 tpy
53-70-3	Dibenz(a,h)anthracene	3.46E-07 lb/MMBtu	2.78E-08 tpy
206-44-0	Fluoranthene	4.03E-06 lb/MMBtu	3.24E-07 tpy
86-73-7	Fluorene	1.28E-05 lb/MMBtu	1.03E-06 tpy
193-39-5	Indeno(1,2,3-cd)pyrene	4.14E-07 lb/MMBtu	3.33E-08 tpy
91-20-3	Naphthalene	1.30E-04 lb/MMBtu	1.04E-05 tpy
85-01-8	Phenanthrene	4.08E-05 lb/MMBtu	3.28E-06 tpy
129-00-0	Pyrene	3.71E-06 lb/MMBtu	2.98E-07 tpy

Total Potential HAP Emissions: 1.26E-04 tpy

[1] Total fuel use based on maximum full-time operation or permit-limited operation as noted below:

EU ID 420a/420b Generators 1,173 gallons

Potential Heat Input: 161 MMBtu/yr

Total Potential Heat Input: 161 MMBtu/yr

Diesel Fuel Heat Content: 137,000 Btu/gal

[2] Reference: AP-42, Tables 3.4-3 and 3.4-4.

Table D1-14. Actual Emissions (After Controls/Limitations) - Hazardous Air Pollutant (HAP)
Natural Gas Fired Turbines

Maximum Total Heat Input: 1,125,592 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations		
CAS No.	**Chemical Name**	**Emission Factor [2]**		**Estimated Emissions**
106-99-0	1,3-Butadiene	4.30E-07	lb/MMBtu	2.42E-04 tpy
75-07-0	Acetaldehyde	4.00E-05	lb/MMBtu	2.25E-02 tpy
107-02-8	Acrolein	6.40E-06	lb/MMBtu	3.60E-03 tpy
71-43-2	Benzene	1.20E-05	lb/MMBtu	6.75E-03 tpy
100-41-4	Ethyl benzene	3.20E-05	lb/MMBtu	1.80E-02 tpy
50-00-0	Formaldehyde	7.10E-04	lb/MMBtu	4.00E-01 tpy
91-20-3	Naphthalene	1.30E-06	lb/MMBtu	7.32E-04 tpy
	Polycyclic Organic Matter (POM)	2.20E-06	lb/MMBtu	1.24E-03 tpy
	Polycyclic aromatic compounds(PAH)	2.20E-06	lb/MMBtu	
75-56-9	Propylene oxide	2.90E-05	lb/MMBtu	1.63E-02 tpy
108-88-3	Toluene	1.30E-04	lb/MMBtu	7.32E-02 tpy
1330-20-7	Xylenes	6.40E-05	lb/MMBtu	3.60E-02 tpy

Total Potential HAP Emissions: 0.58 tpy

Notes:

[1] Total fuel use based on maximum full-time operation or permit-limited operation as noted below:

EU ID 500	Turbine	11,862 kW			
	Potential Heat Input:		224,610	MMBtu/yr, operating	1,768 hr/yr
EU ID 501	Turbine	11,862 kW			
	Potential Heat Input:		900,982	MMBtu/yr, operating	7,092 hr/yr

Total Potential Heat Input: 1,125,592 MMBtu/yr

Turbine Heat Rate: 10,710 Btu/KW-hr

[2] Reference: AP-42, Tables 3.1-3.

Table D1-15. Actual Emissions (After Controls/Limitations) - Hazardous Air Pollutant (HAP)
Natural Gas Fired Heaters

Maximum Total Heat Input: 282,913 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**Emission Factor [2,3]**	**Estimated Emissions**
106-46-7	1,4-Dichlorobenzene(p)	1.20E-03 lb/MMscf	1.61E-04 tpy
71-43-2	Benzene	2.10E-03 lb/MMscf	2.81E-04 tpy
50-00-0	Formaldehyde	7.52E-02 lb/MMscf	1.01E-02 tpy
	Lead Compounds	5.00E-04 lb/MMscf	7.07E-02 tpy
110-54-3	N-Hexane	1.8 lb/MMscf	2.41E-01 tpy
	Polycyclic Organic Matter (POM)	7.14E-04 lb/MMscf	9.57E-05 tpy
	Polycyclic aromatic compounds(PAH)		
91-57-6	2-Methylnaphthalene	2.40E-05 lb/MMscf	3.21E-06 tpy
83-32-9	Acenaphthene	1.80E-05 lb/MMscf	2.41E-06 tpy
203-96-8	Acenaphthylene	1.80E-06 lb/MMscf	2.41E-07 tpy
120-12-7	Anthracene	2.40E-06 lb/MMscf	3.21E-07 tpy
56-55-3	Benzo(a)anthracene	1.80E-06 lb/MMscf	2.41E-07 tpy
205-99-2	Benzo(b)fluoranthene	1.80E-06 lb/MMscf	2.41E-07 tpy
207-08-9	Benzo(k)fluoranthene	1.80E-06 lb/MMscf	2.41E-07 tpy
50-32-8	Benzo(a)pyrene	1.20E-06 lb/MMscf	1.61E-07 tpy
191-24-2	Benzo(g,h,i)perylene	1.20E-06 lb/MMscf	1.61E-07 tpy
218-01-9	Chrysene	1.80E-06 lb/MMscf	2.41E-07 tpy
53-70-3	Dibenz(a,h)anthracene	1.20E-06 lb/MMscf	1.61E-07 tpy
	7,12-dimethylbenzanthracene	1.60E-05 lb/MMscf	2.14E-06 tpy
206-44-0	Fluoranthene	3.00E-06 lb/MMscf	4.02E-07 tpy
86-73-7	Fluorene	2.80E-06 lb/MMscf	3.75E-07 tpy
193-39-5	Ideno(1,2,3-cd)pyrene	1.80E-06 lb/MMscf	2.41E-07 tpy
56-49-5	3-methylcholanthrene	1.80E-06 lb/MMscf	2.41E-07 tpy
91-20-3	Naphthalene	6.10E-04 lb/MMscf	8.17E-05 tpy
85-01-8	Phenanthrene	1.70E-05 lb/MMscf	2.28E-06 tpy
129-00-0	Pyrene	5.00E-06 lb/MMscf	6.70E-07 tpy
108-88-3	Toluene	3.40E-03 lb/MMscf	4.55E-04 tpy

Total Potential HAP Emissions: 0.32 tpy

[1] Total fuel use based on maximum full-time operation or permit-limited operation as noted below:

EU ID 503	Production Heater	34.0 MMBtu/hr			
	Potential Heat Input:		272,170 MMBtu/yr, operating	8,005	hr/yr
EU ID 505	TEG Reboiler	1.34 MMBtu/hr			
	Potential Heat Input:		10,743 MMBtu/yr, operating	8,017	hr/yr

Total Potential Heat Input: 282,913 MMBtu/yr

[2] Reference: AP-42, Tables 1.4-2 and 1.4-3.

[3] Gas HHV 2022 Average: 1,056 Btu/scf

Table D1-16. Actual Emissions (After Controls/Limitations) - Hazardous Air Pollutant (HAP)
Diesel Fired Heaters

Maximum Total Heat Input: 0 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**Emission Factor [2,3]**	**Estimated Emissions**
	Arsenic Compounds	4.00E-06 lb/MMBtu	0 tpy
71-43-2	Benzene	1.56E-06 lb/MMBtu	0 tpy
	Beryllium Compounds	3.00E-06 lb/MMBtu	0 tpy
	Cadmium Compounds	3.00E-06 lb/MMBtu	0 tpy
	Chromium Compounds	3.00E-06 lb/MMBtu	0 tpy
100-41-4	Ethyl benzene	4.64E-07 lb/MMBtu	0 tpy
50-00-0	Formaldehyde	2.41E-04 lb/MMBtu	0 tpy
	Lead Compounds	9.00E-06 lb/MMBtu	0 tpy
	Manganese Compounds	6.00E-06 lb/MMBtu	0 tpy
	Mercury Compounds	3.00E-06 lb/MMBtu	0 tpy
	Nickel Compounds	3.00E-06 lb/MMBtu	0 tpy
	Polycyclic Organic Matter (POM)	2.41E-05 lb/MMBtu	0 tpy
	Polycyclic aromatic compounds(PAH)		
83-32-9	Acenaphthylene	1.54E-07 lb/MMBtu	0 tpy
208-96-8	Acenaphthene	1.85E-09 lb/MMBtu	0 tpy
120-12-7	Anthracene	8.91E-09 lb/MMBtu	0 tpy
56-55-3	Benzo(a)anthracene	2.93E-08 lb/MMBtu	0 tpy
205-99-2/207-08-9	Benzo(b,k)fluoranthene	1.08E-08 lb/MMBtu	0 tpy
191-24-2	Benzo(g,h,l)perylene	1.65E-08 lb/MMBtu	0 tpy
218-01-9	Chrysene	1.74E-08 lb/MMBtu	0 tpy
53-70-3	Dibenz(a,h)anthracene	1.22E-08 lb/MMBtu	0 tpy
206-44-0	Fluoranthene	3.53E-08 lb/MMBtu	0 tpy
86-73-7	Fluorene	3.26E-08 lb/MMBtu	0 tpy
193-39-5	Indeno(1,2,3-cd)pyrene	1.56E-08 lb/MMBtu	0 tpy
91-20-3	Naphthalene	8.25E-06 lb/MMBtu	0 tpy
85-01-8	Phenanthrene	7.66E-08 lb/MMBtu	0 tpy
129-00-0	Pyrene	3.10E-08 lb/MMBtu	0 tpy
	Selenium Compounds	1.50E-05 lb/MMBtu	0 tpy
108-88-3	Toluene	4.53E-05 lb/MMBtu	0 tpy
71-55-6	1,1,1-Trichloroethane	1.72E-06 lb/MMBtu	0 tpy
1330-20-7	Xylenes	7.96E-07 lb/MMBtu	0 tpy

Total Potential HAP Emissions: 0 tpy

[1] Total fuel use based on maximum full-time operation or permit-limited operation as noted below:

EU ID I Rig Boilers and Heaters 0 gallons

Potential Heat Input: 0 MMBtu/yr

Total Potential Heat Input: 0 MMBtu/yr

[2] Reference: AP-42, Tables 1.3-8, 1.3-9, and 1.3-10.

[3] Diesel high heat value: 137,000 Btu/gal

Table D1-17. Actual Emissions (After Controls/Limitations) - Hazardous Air Pollutant (HAP)
Flares

Maximum Total Heat Input: 5.6 MMscf/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations		
CAS No.	**Chemical Name**	**Emission Factor [2,3]**		**Estimated Emissions**
	Flared Gas:			
75-07-0	Acetaldehyde	0.043	lb/MMscf	1.19E-04 tpy
107-02-8	Acrolein	0.010	lb/MMscf	2.78E-05 tpy
71-43-2	Benzene	0.159	lb/MMscf	4.42E-04 tpy
100-41-4	Ethyl benzene	1.444	lb/MMscf	4.01E-03 tpy
50-00-0	Formaldehyde	1.169	lb/MMscf	3.25E-03 tpy
110-54-3	N-Hexane	0.029	lb/MMscf	8.05E-05 tpy
91-20-3	Naphthalene	0.011	lb/MMscf	3.05E-05 tpy
108-88-3	Toluene	0.058	lb/MMscf	1.61E-04 tpy
1330-20-7	Xylenes	0.029	lb/MMscf	8.05E-05 tpy
	Polycyclic Organic Matter (POM)	0.014	lb/MMscf	3.89E-05 tpy
	Uncombusted Gas:			
110-54-3	N-Hexane	10.297	lb/MMscf	2.9E-02 tpy

Total Potential HAP Emissions: 0.04 tpy

[1] Total fuel use based on maximum full-time operation or permit-limited operation as noted below:

EU ID 507 Flare 5,554 Mscf/yr

Potential Heat Input: 5,554 Mscf/yr, operating 8,760 hr/yr

Total Potential Heat Input: 5.6 MMscf/yr

[2] Reference: VCAPCD AB 2588 (Flares - Natural Gas)

[3] Flare destruction efficiency estimated at 98%.

[3] October 9, 2017 gas analysis, 0.227 mole percent hexane plus (0.20 lbs/lb-mol).

Table D1-18. Actual Emissions (After Controls/Limitations) - Hazardous Air Pollutant (HAP)
Insignificant Incinerators

Maximum Total Heat Input: 38 ton/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations		
CAS No.	**Chemical Name**	**Emission Factor [2]**		**Estimated Emissions**
	Arsenic Compounds	6.69E-04	lb/ton	1.25765E-05 tpy
	Cadmium Compounds	2.41E-03	lb/ton	4.53E-05 tpy
	Chromium Compounds	3.31E-03	lb/ton	6.22E-05 tpy
7647-01-0	Hydrochloric Acid	2.15E+00	lb/ton	0.04 tpy
	Mercury Compounds	5.60E-03	lb/ton	1.05E-04 tpy
	Nickel Compounds	5.52E-03	lb/ton	1.04E-04 tpy
	Dioxins/Furans	2.94E-06	lb/ton	5.53E-08 tpy

Total Potential HAP Emissions: 0.04 tpy

Notes:

[1] Total incinerated weight based on maximum operation for the following:

EU ID 422	Smart Ash 100-A Incinerator	0.04	tons/hr	
	Potential Heat Input:			3 tons/yr
EU ID 502	Therm-Tec-G-12 Incinerator	85	lb/hr	
	Potential Heat Input:			35 tons/yr
	Total Potential Waste incinerated:			**38 ton/yr**

[2] Reference: AP-42, Tables 2.1-9, Modular Starved-Air Combustors.

Table D1-19. Actual Emissions (After Controls/Limitations) - Hazardous Air Pollutant (HAP)
Insignificant Diesel Fired Heaters

Maximum Total Heat Input: 1,906 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**Emission Factor [2,3]**	**Estimated Emissions**
	Arsenic Compounds	4.00E-06 lb/MMBtu	3.81E-06 tpy
71-43-2	Benzene	1.56E-06 lb/MMBtu	1.49E-06 tpy
	Beryllium Compounds	3.00E-06 lb/MMBtu	2.86E-06 tpy
	Cadmium Compounds	3.00E-06 lb/MMBtu	2.86E-06 tpy
	Chromium Compounds	3.00E-06 lb/MMBtu	2.86E-06 tpy
100-41-4	Ethyl benzene	4.64E-07 lb/MMBtu	4.42E-07 tpy
50-00-0	Formaldehyde	2.41E-04 lb/MMBtu	2.30E-04 tpy
	Lead Compounds	9.00E-06 lb/MMBtu	8.58E-06 tpy
	Manganese Compounds	6.00E-06 lb/MMBtu	5.72E-06 tpy
	Mercury Compounds	3.00E-06 lb/MMBtu	2.86E-06 tpy
	Nickel Compounds	3.00E-06 lb/MMBtu	2.86E-06 tpy
	Polycyclic Organic Matter (POM)	2.41E-05 lb/MMBtu	2.30E-05 tpy
	Polycyclic aromatic compounds(PAH)		
83-32-9	Acenaphthylene	1.54E-07 lb/MMBtu	1.47E-07 tpy
208-96-8	Acenaphthene	1.85E-09 lb/MMBtu	1.76E-09 tpy
120-12-7	Anthracene	8.91E-09 lb/MMBtu	8.49E-09 tpy
56-55-3	Benzo(a)anthracene	2.93E-08 lb/MMBtu	2.79E-08 tpy
205-99-2/207-08-9	Benzo(b,k)fluoranthene	1.08E-08 lb/MMBtu	1.03E-08 tpy
191-24-2	Benzo(g,h,l)perylene	1.65E-08 lb/MMBtu	1.57E-08 tpy
218-01-9	Chrysene	1.74E-08 lb/MMBtu	1.66E-08 tpy
53-70-3	Dibenz(a,h)anthracene	1.22E-08 lb/MMBtu	1.16E-08 tpy
206-44-0	Fluoranthene	3.53E-08 lb/MMBtu	3.37E-08 tpy
86-73-7	Fluorene	3.26E-08 lb/MMBtu	3.11E-08 tpy
193-39-5	Indeno(1,2,3-cd)pyrene	1.56E-08 lb/MMBtu	1.49E-08 tpy
91-20-3	Naphthalene	8.25E-06 lb/MMBtu	7.86E-06 tpy
85-01-8	Phenanthrene	7.66E-08 lb/MMBtu	7.30E-08 tpy
129-00-0	Pyrene	3.10E-08 lb/MMBtu	2.96E-08 tpy
NA	Selenium Compounds	1.50E-05 lb/MMBtu	1.43E-05 tpy
108-88-3	Toluene	4.53E-05 lb/MMBtu	4.31E-05 tpy
71-55-6	1,1,1-Trichloroethane	1.72E-06 lb/MMBtu	1.64E-06 tpy
1330-20-7	Xylenes	7.96E-07 lb/MMBtu	7.58E-07 tpy

Total Potential HAP Emissions: 0.0003 tpy

[1] Total fuel use based on maximum full-time operation or permit-limited operation as noted below:

EU ID 607	Indirect Fire Heater	1 MMBtu/hr			
	Potential Heat Input:		387	MMBtu/yr, operating	387 hr/yr
EU ID 608	Indirect Fire Heater	1 MMBtu/hr			
	Potential Heat Input:		386	MMBtu/yr, operating	386 hr/yr
EU ID 611	Indirect Fire Heater	1 MMBtu/hr			
	Potential Heat Input:		171	MMBtu/yr, operating	171 hr/yr
EU ID 612	Indirect Fire Heater	1 MMBtu/hr			
	Potential Heat Input:		650	MMBtu/yr, operating	650 hr/yr
	Hot Oil Heater	6 MMBtu/hr			
			312	MMBtu/yr, operating	52 hr/yr
	Total Potential Heat Input:		**1,906**	**MMBtu/yr**	

[2] Reference: AP-42, Tables 1.3.8, 1.3-9, and 1.3-10.

[3] Diesel high heat value: 137,000 Btu/gal

Table D2-1. Potential Annual Emissions (Before Controls/Limitations) Summary
Savant Alaska, LLC - Badami Development Facility

Potential to Emit	Regulated Air Pollutant Emissions (tons per year) [1,2]							
	NO_X	CO	PM_{10}	$PM_{2.5}$ [3]	VOC	SO_2	GHG [4,5]	HAP [6]
Significant	463.5	3,530.9	15.8	15.8	92.8	58.1	184,377	3.4
Insignificant	7.1	8.4	6.1	6.1	5.5	0.9	7,857	0.8
Total Emissions	**470.6**	**3,539.3**	**22.0**	**22.0**	**98.3**	**59.0**	**192,234**	**4.2**

Notes:

[1] Emissions are based on maximum potential operation.

[2] Regulated air pollutant calculations based on AP-42 emission factors, manufacturer data, and mass balances as shown in accompanying spreadsheets.

[3] $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions.

[4] GHG emissions are defined as CO_2e emissions. CO_2e is the summation of CO_2, CH_4, and N_2O, applying the global warming potential for each pollutant.

[5] Per 40 CFR 71.2, GHGs are subject to regulation beginning on July 1, 2011.

[6] See individual emissions unit category HAP emissions calculations for details on methodology and assumptions (electronic copy).

Table D2-2a. Significant Emissions Unit Inventory
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel	Potential Annual	Maximum
ID	Description	Make/Model	Type	Operation	Capacity/Output
420a	Generator	Cummins QSK50-G4	Diesel	8,760 hr/hr	1,971 hp
421a	Generator	Cummins QSK50-G4	Diesel	8,760 hr/hr	1,971 hp
500	Turbine	Solar Mars 90	Fuel Gas	8,760 hr/hr	11,862 kW
501	Turbine	Solar Mars 90	Fuel Gas	8,760 hr/hr	11,862 kW
503	Production Heater	NATCO	Fuel Gas	8,760 hr/hr	34 MMBtu/hr
505	TEG Reboiler	NATCO	Fuel Gas	8,760 hr/hr	1.34 MMBtu/hr
507	Flare	Mac Injector 100 Series	Fuel Gas and Produced Gas	8,760 hr/hr	257.9 MMscf/yr
Drill Rig Equipment					
1	Rig Engines	Various	Diesel/Fuel Gas	950,000 gal/yr [1]	Various
8	Rig Boilers and Heaters	Various	Diesel/Fuel Gas		Various

[1] Title V Permit AQ0417TVP03 Condition 16 limits the operation of EU IDs 1 and 8 to 950,000 gallons of liquid fuel during any 12 consecutive month period. Minor Permit AQ0417MSS07, Revision 1 allows for the combustion of either liquid fuel or fuel gas, with the limit based on liquid fuel combustion. Since the ratings of the rig boilers and heaters are not specified, the fuel limit is used in the calculations.

Table D2-2b. Insignificant Emissions Unit Inventory
Savant Alaska, LLC - Badami Development Facility

Emission Unit		Fuel	Rating/Size	Potential Annual
ID	Description	Type		Operation
417	Diesel Tank	NA	15,000 barrels	8,760 hr/yr
418	Methanol Tank	NA	450 barrels	8,760 hr/yr
422	Smart Ash 100-A Incinerator	Oily Waste	0.035 tons/hr	8,760 hr/yr
502	Therm-Tec-G-12 Incinerator	Propane/Fuel Gas	1.6 MMBtu/hr	8,760 hr/yr
		Waste	85.0 lb/hr	8,760 hr/yr
607	Indirect Fire Heater	Diesel	1.0 MMBtu/hr	8,760 hr/yr
608	Indirect Fire Heater	Diesel	1.0 MMBtu/hr	8,760 hr/yr
611	Indirect Fire Heater	Diesel	1.0 MMBtu/hr	8,760 hr/yr
612	Indirect Fire Heater	Diesel	1.0 MMBtu/hr	8,760 hr/yr
NA	Hot Oil Heater	Diesel	6.0 MMBtu/hr	8,760 hr/yr

Table D2-2c. Intermittently Used Oilfield Support Equipment (IUOSE) Inventory
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Maximum Capacity	IUOSE	Non-Road Engine	Use (see below)
Quantity	Description	Make/Model					
1	Grader	Caterpillar 14H	Diesel	215 hp	Yes	Yes	B
1	Loader	Caterpillar 966F	Diesel	218 hp	Yes	Yes	B
1	Excavator	Hitachi XE220LC	Diesel	160 hp	Yes	Yes	B
1	Bobcat	Kubota V2203-E	Diesel	50 hp	Yes	Yes	B
1	Bobcat Skid Steer Loader	Deutz T200	Diesel	72 hp	Yes	Yes	B
1	Loader	Caterpillar 966G	Diesel	439 hp	Yes	Yes	B
1	Ingersoll Rand Pro Pac	Cummins 5.9 SD150D	Diesel	185 hp	Yes	Yes	B
1	Kodiak Snow Blower	Caterpillar C13	Diesel	520 hp	Yes	Yes	B
1	Bulldozer	Caterpillar 3306	Diesel	225 hp	Yes	Yes	B
1	H-Series Guzzler	Caterpillar C10	Diesel	238 hp	Yes	Yes	B
1	Generator (mounted on Guzzler)	Yanmar 3Tne	Diesel	13 hp	Yes	Yes	B
1	Fuel Truck	Detroit 6067E	Diesel	350 hp	Yes	Yes	B
1	Dump Truck	Caterpillar 406	Diesel	380 hp	Yes	Yes	B
1	Box Truck	Caterpillar 3126	Diesel	230 hp	Yes	Yes	B
1	Tucker Snow Vehicle	Cummins QSB3.9	Diesel	130 hp	Yes	Yes	B
1	Argo 750 HDI	Kohler LH 775	Gasoline	31 hp	Yes	Yes	B
1	Genie Zoom Boom	Perkins 1104C-44T	Diesel	99 hp	Yes	Yes	A&B
1	Air Compressor	Deutz TD20111l04w	Diesel	63 hp	Yes	Yes	A&B
1	Triplex Pump	Cummins B3.3	Diesel	85 hp	Yes	Yes	A&B
1	Hot Oil Generator	Kubota D1105	Diesel	21 hp	Yes	Yes	A&B
1	Hot Oil Tractor/Pump	Cummins N-14	Diesel	330 hp	Yes	Yes	A&B
1	Generator (mounted on Guzzler)	Cummins 4BTA 5.9	Diesel	67 hp	Yes	Yes	A&B
1	EU BAD 022 - Hot Oil Heater	Webster Cyclonetic JB2-50-YB110-MR	Diesel	6 MMBtu/hr	Yes	No	A&B
1	EU 603a - Air Compressor	Sullair 200HDPQAi4	Diesel	55 hp	Yes	Yes	A&B
1	EU 600 - Crane	Grove RT635C	Diesel	215 hp	Yes	Yes	A&B
1	EU BAD 034a - Manlift	Perkins 804C	Diesel	63 hp	Yes	Yes	A&B
1	EU 604 - Welder	Bobcat 250	Diesel	38 hp	Yes	Yes	A&B
1	EU BAD 036 - Portable Welder Engine	Miller Bobcat MD#907039	Diesel	20 hp	Yes	Yes	A&B
1	LED Light Plant	Perkins 403D	Diesel	11 hp	Yes	Yes	C
2	EU 601/602 - Light Plants	Unknown	Diesel	12.1 hp	Yes	Yes	C
4	ES700 Indirect Fire Heater Motor (used with EU 607608/611/612)	Kubota D1105	Diesel	13 hp	Yes	Yes	C
1	EU 607 (BAD 028) - Indirect Fire Heater	Tioga ES700 - Heater #1	Diesel	1 MMBtu/hr	Yes	No	C
1	EU 608 (BAD 029) - Indirect Fire Heater	Tioga ES700 - Heater #2	Diesel	1 MMBtu/hr	Yes	No	C
1	EU 611 (BAD 030) - Indirect Fire Heater	Tioga ES700 - Heater #3	Diesel	1 MMBtu/hr	Yes	No	C
1	EU 612 (BAD 031) - Indirect Fire Heater	Tioga ES700 - Heater #4	Diesel	1 MMBtu/hr	Yes	No	C
10	Rig Light Plant	Unknown	Diesel	16 hp, each	Yes	Yes	D
1	Frac Engine	Caterpillar 3512	Diesel	1,800 hp	Yes	Yes	D
1	Cement Pump Van Onan	Unknown	Diesel	325 hp	Yes	Yes	D
1	Cement Batch Mixer Onan	Unknown	Diesel	34 hp	Yes	Yes	D
1	Slickline Generator	Unknown	Diesel	31 hp	Yes	Yes	D
1	Slickline Powerpack	John Deere	Diesel	120 hp	Yes	Yes	D
1	E-Line Logger	Unknown	Diesel	310 hp	Yes	Yes	D
1	E-Line Grease Skid	Unknown	Diesel	90 hp	Yes	Yes	D
1	E-Line Spare Generator	Unknown	Diesel	50 hp	Yes	Yes	D
1	CTU Onan	Unknown	Diesel	34 hp	Yes	Yes	D
1	CTU Power Pack	Unknown	Diesel	425 hp	Yes	Yes	D
1	CTU Tractor/Pump	Unknown	Diesel	450 hp	Yes	Yes	D

Uses:

A - Oil Well Servicing and Maintenance

B - General Oilfield Maintenance for Pipelines, Roads, and Other Existing Infrastructure.

C - Oil Well Servicing and General Oilfield Maintenance for Pipelines, Roads, and Other Existing Infrastructure. Units are in storage and used in winter months as needed.

D - Oil Well Servicing and Maintenance, contractor equipment not permanently onsite (ratings are estimated).

Table D2-3. Potential Emissions (Before Controls/Limitations) - Oxides of Nitrogen (NO_X)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Factor Reference	Emission Factor	Potential Annual Operation	Potential Annual Emissions [1]
ID	Description	Rating/Capacity					
Significant Emission Units							
420a	Generator	1,971 hp	Diesel	AQ0417TVP03, Cond. 36.1	6.4 g/kW-hr	8,760 hr/hr	90.8 tpy
421a	Generator	1,971 hp	Diesel	AQ0417TVP03, Cond. 36.1	6.4 g/kW-hr	8,760 hr/hr	90.8 tpy
500	Turbine	11,862 kW	Fuel Gas	AQ0417TVP03, Cond. 17.1b(i)	28.4 lb/hr	8,760 hr/hr	124.4 tpy
501	Turbine	11,862 kW	Fuel Gas	AQ0417TVP03, Cond. 17.1b(i)	28.4 lb/hr	8,760 hr/hr	124.4 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	AQ0417TVP03, Cond. 17.1b(ii)	0.095 lb/MMBtu	8,760 hr/hr	14.1 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	AQ0417TVP03, Cond. 17.1b(iii)	0.08 lb/MMBtu	8,760 hr/hr	0.5 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	AP-42, Table 13.5-1	0.068 lb/MMBtu	8,760 hr/hr	8.9 tpy
Drill Rig Equipment							
1	Rig Engines	Various	Diesel/Fuel Gas	AP-42, Table 1.3-1	20 $lb/10^3$ gal	950,000 gallons	9.5 tpy [2]
8	Rig Boilers and Heaters	Various	Diesel/Fuel Gas				
Significant Emission Units - Estimated Potential Emissions - NO_X							**463.5 tpy**
Insignificant Emission Units							
417	Diesel Tank	15,000 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
418	Methanol Tank	450 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	AP-42, Table 2.1-12	2 lb/ton	8,760 hr/yr	0.3 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	AP-42, Table 2.1-12	2 lb/ton	8,760 hr/yr	0.4 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	20 $lb/10^3$ gal	8,760 hr/yr	0.6 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	20 $lb/10^3$ gal	8,760 hr/yr	0.6 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	20 $lb/10^3$ gal	8,760 hr/yr	0.6 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	20 $lb/10^3$ gal	8,760 hr/yr	0.6 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	20 $lb/10^3$ gal	8,760 hr/yr	3.8 tpy
Insignificant Emission Units - Estimated Potential Emissions - NO_X							**7.1 tpy**
Total Estimated Potential Emissions - NO_X							**470.6 tpy**

Notes:

[1] Parameters and Conversions:

Average gross heating value (AP-42, Section 1.4)	1,020	Btu/scf
Diesel Heat Content (AP-42, Appendix A)	137,000	Btu/gal
Engine heat rate (AP-42, Section 3.3)	7,000	Btu/hp-hr

[2] Calculations are performed for boilers and heaters. Nonroad emissions are not included when determining stationary source classification.

Table D2-4. Potential Emissions (Before Controls/Limitations) - Carbon Monoxide (CO)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Factor Reference	Emission Factor	Potential Annual Operation	Potential Annual Emissions [1]
ID	Description	Rating/Capacity					
Significant Emission Units							
420a	Generator	1,971 hp	Diesel	AQ0417TVP03, Cond. 36.1	3.5 g/kW-hr	8,760 hr/hr	49.7 tpy
421a	Generator	1,971 hp	Diesel	AQ0417TVP03, Cond. 36.1	3.5 g/kW-hr	8,760 hr/hr	49.7 tpy
500	Turbine	11,862 kW	Fuel Gas	AQ0417TVP03, Cond. 17.2a(i)	385 lb/hr	8,760 hr/hr	1,686 tpy
501	Turbine	11,862 kW	Fuel Gas	AQ0417TVP03, Cond. 17.2a(i)	385 lb/hr	8,760 hr/hr	1,686 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	AQ0417TVP03, Cond. 17.2a(ii)	3.4 lb/hr	8,760 hr/hr	14.9 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	AQ0417TVP03, Cond. 17.2a(iii)	0.15 lb/MMBtu	8,760 hr/hr	0.9 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	AP-42, Table 13.5-2	0.31 lb/MMBtu	8,760 hr/hr	40.8 tpy
Drill Rig Equipment							
1	Rig Engines	Various	Diesel/Fuel Gas	AP-42, Table 3.4-1	5 $lb/10^3$ gal	950,000 gallons	2.4 tpy [3]
8	Rig Boilers and Heaters	Various	Diesel/Fuel Gas				
Significant Emission Units - Estimated Potential Emissions - CO							**3,530.9 tpy**
Insignificant Emission Units							
417	Diesel Tank	15,000 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
418	Methanol Tank	450 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	AP-42, Table 2.1-12	20 lb/ton	8,760 hr/yr	3.1 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	AP-42, Table 2.1-12	20 lb/ton	8,760 hr/yr	3.7 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	5 $lb/10^3$ gal	8,760 hr/yr	0.2 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	5 $lb/10^3$ gal	8,760 hr/yr	0.2 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	5 $lb/10^3$ gal	8,760 hr/yr	0.2 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	5 $lb/10^3$ gal	8,760 hr/yr	0.2 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	5 $lb/10^3$ gal	8,760 hr/yr	1.0 tpy
Insignificant Emission Units - Estimated Potential Emissions - CO							**8.4 tpy**
Total Estimated Potential Emissions - CO							**3539.3 tpy**

Notes:

[1] Parameters and Conversions:
Average gross heating value (AP-42, Section 1.4) 1,020 Btu/scf
Diesel Heat Content (AP-42, Appendix A) 137,000 Btu/gal

[2] Combined limit from Condition 17.2b of AQ0417TV03.

[3] Calculations are performed for boilers and heaters. Nonroad emissions are not included when determining stationary source classification.

Table D2-5. Potential Emissions (Before Controls/Limitations) - Particulate Matter Less Than 10 Microns (PM_{10})
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Factor Reference	Emission Factor	Potential Annual Operation	Potential Annual Emissions [1]
ID	Description	Rating/Capacity					
Significant Emission Units							
420a	Generator	1,971 hp	Diesel	AQ0417TVP03, Cond. 36.1	0.20 g/kW-hr	8,760 hr/hr	2.8 tpy
421a	Generator	1,971 hp	Diesel	AQ0417TVP03, Cond. 36.1	0.20 g/kW-hr	8,760 hr/hr	2.8 tpy
500	Turbine	11,862 kW	Fuel Gas	AP-42, Table 3.1-1	0.0066 lb/MMBtu	8,760 hr/hr	3.7 tpy
501	Turbine	11,862 kW	Fuel Gas	AP-42, Table 3.1-1	0.0066 lb/MMBtu	8,760 hr/hr	3.7 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	AP-42, Table 1.4-2	7.6 lb/MMscf	8,760 hr/hr	1.1 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	AP-42, Table 1.4-2	7.6 lb/MMscf	8,760 hr/hr	0.04 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	AP-42, Table 13.5-1	40 µg/L	8,760 hr/hr	0.1 tpy
Drill Rig Equipment							
1	Rig Engines	Various	Diesel/Fuel Gas	AP-42, Table 1.3-1 and 1.3-2	3.3 $lb/10^3$ gal	950,000 gallons	1.6 tpy [2]
8	Rig Boilers and Heaters	Various	Diesel/Fuel Gas				
Significant Emission Units - Estimated Potential Emissions - PM_{10}							**15.8 tpy**
Insignificant Emission Units							
417	Diesel Tank	15,000 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
418	Methanol Tank	450 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	AP-42, Table 2.1-12	15 lb/ton	8,760 hr/yr	2.3 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	AP-42, Table 2.1-12	15 lb/ton	8,760 hr/yr	2.8 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1 and 1.3-2	3.3 $lb/10^3$ gal	8,760 hr/yr	0.1 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1 and 1.3-2	3.3 $lb/10^3$ gal	8,760 hr/yr	0.1 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1 and 1.3-2	3.3 $lb/10^3$ gal	8,760 hr/yr	0.1 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1 and 1.3-2	3.3 $lb/10^3$ gal	8,760 hr/yr	0.1 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1 and 1.3-2	3.3 $lb/10^3$ gal	8,760 hr/yr	0.6 tpy
Insignificant Emission Units - Estimated Potential Emissions - PM_{10}							**6.1 tpy**
Total Estimated Potential Emissions - PM_{10}							**22.0 tpy**

Notes:

[1] Parameters and Conversions:

Average gross heating value (AP-42, Section 1.4)	1,020	Btu/scf
Diesel Heat Content (AP-42, Appendix A)	137,000	Btu/gal
Vendor turbine Heat Rate	10,710	Btu/kW-hr
F-Factor (40 CFR 60, Method 19)	8,710	dscf/MMBtu

[2] Calculations are performed for boilers and heaters. Nonroad emissions are not included in assessable (permit applicability) emissions.

Table D2-6a. Potential Emissions (Before Controls/Limitations) - Volatile Organic Compounds (VOCs)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Factor Reference	Emission Factor	Potential Annual Operation	Potential Annual Emissions [1]
ID	Description	Rating/Capacity					
Significant Emission Units							
420a	Generator	1,971 hp	Diesel	Vendor Data	0.09 g/hp-hr	8,760 hr/hr	1.7 tpy
421a	Generator	1,971 hp	Diesel	Vendor Data	0.05 g/hp-hr	8,760 hr/hr	1.0 tpy
500	Turbine	11,862 kW	Fuel Gas	AP-42, Table 3.1-2a	0.0021 lb/MMBtu	8,760 hr/hr	1.2 tpy
501	Turbine	11,862 kW	Fuel Gas	AP-42, Table 3.1-2a	0.0021 lb/MMBtu	8,760 hr/hr	1.2 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	AP-42, Table 1.4-2	5.5 lb/MMscf	8,760 hr/hr	0.8 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	AP-42, Table 1.4-2	5.5 lb/MMscf	8,760 hr/hr	0.03 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	AP-42 Table 13.5-2	0.66 lb/MMBtu	8,760 hr/hr	86.8 tpy
Drill Rig Equipment							
1	Rig Engines	Various	Diesel/Fuel Gas	AP-42, Table 1.3-3	0.34 $lb/10^3$ gal	950,000 gallons	0.2 tpy [2]
8	Rig Boilers and Heaters	Various	Diesel/Fuel Gas				
Significant Emission Units - Estimated Potential Emissions - VOC							**92.8 tpy**
Insignificant Emission Units							
417	Diesel Tank	15,000 barrels	NA	See Table D2-6b	NA	8,760 hr/yr	0.08 tpy
418	Methanol Tank	450 barrels	NA	See Table D2-6b	NA	8,760 hr/yr	0.2 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	AP-42, Table 2.1-12	15 lb/ton	8,760 hr/yr	2.3 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	AP-42, Table 2.1-12	15 lb/ton	8,760 hr/yr	2.8 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-3	0.34 $lb/10^3$ gal	8,760 hr/yr	0.01 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-3	0.34 $lb/10^3$ gal	8,760 hr/yr	0.01 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-3	0.34 $lb/10^3$ gal	8,760 hr/yr	0.01 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-3	0.34 $lb/10^3$ gal	8,760 hr/yr	0.01 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	AP-42, Table 1.3-3	0.34 $lb/10^3$ gal	8,760 hr/yr	0.07 tpy
Insignificant Emission Units - Estimated Potential Emissions - VOC							**5.5 tpy**
Total Estimated Potential Emissions - VOC							**98.3 tpy**

Notes:

[1] Parameters and Conversions:

Average gross heating value (AP-42, Section 1.4)	1,020 Btu/scf
Diesel Heat Content (AP-42, Appendix A)	137,000 Btu/gal
Vendor turbine Heat Rate	10,710 Btu/kW-hr

[2] Calculations are performed for boilers and heaters. Nonroad emissions are not included in assessable (permit applicability) emissions.

Table D2-6b. Potential Emissions (Before Controls/Limitations) - Volatile Organic Compounds (VOCs)

Savant Alaska, LLC - Badami Development Facility

Parameter	Factor Reference	Emissions Unit ID	
		417	418
Orientation	NA	Vertical	Horizontal
Contents	NA	ULSD	Methanol
Diameter (ft), D	NA	67	9.3
Effective Diameter (ft), D_E	AP-42, Section 7.1, Equation 1-14	---	21.2
Height (ft), H_S	NA	24	---
Effective Height (ft), H_E	AP-42, Section 7.1, Equation 1-15	---	7.3
Length (ft), L	NA	---	38
Color	NA	White	White
Maximum Liquid Height (ft), H_L	NA	23	---
Capacity (gal)	NA	630,000	18,900
Throughput (gal/yr) [1]	NA	7,560,000	226,800
Turnovers	NA	12	12
Paint Condition	NA	New	New
Standing Loss (L_S) Calculations [2,3]			
K_E	AP-42, Section 7.1, Equation 1-12	0.020	0.020
H_{VO} (ft)	AP-42, Section 7.1, Equation 1-16	1.70	3.7
H_{RO} (ft)	AP-42, Section 7.1, Equation 1-17	0.70	0.10
K_S	AP-42, Section 7.1, Equation 1-21	0.999	0.778
T_{AA} (^oR)	AP-42, Section 7.1, Equation 1-30	470.30	470.30
T_B (^oR)	AP-42, Section 7.1, Equation 1-31	470.73	470.73
T_V (^oR) - uninsulated	AP-42, Section 7.1, Equation 1-33	471.71	471.71
W_V (lb/ft^3)	AP-42, Section 7.1, Equation 1-22	1.54E-04	9.34E-03
L_S (lb/yr)	AP-42, Section 7.1, Equation 1-4	6.8	69.3
Working Loss (L_W) Calculations [3]			
Q (bbl/yr)	NA	180,000	5,400
V_Q (ft^3)	AP-42, Section 7.1, Equation 1-39	1,010,520	30,316
K_N [4]	AP-42, Section 7.1, Equation 1-35	1	1
L_W (lb/yr)	AP-42, Section 7.1, Equation 1-35	155.7	283.2
TOTAL VOCs L_T (tpy)	**AP-42, Section 7.1, Equation 1-1**	**0.08**	**0.2**

Note:

[1] Tanks are filled with submerged loading.

[2] Meteorological Inputs (Deadhorse, AK):

	T_{AX} =	16.6	^oF
		476.3	^oR
AP-42, Section 7.1, Table 7.1-6	T_{AN} =	4.6	^oF
		464.3	^oR
AP-42, Section 7.1, Table 7.1-7	α =	0.17	White, New
	I =	838	Btu/ft^2-d

[3] Constants: From the 1995 version of AP-42

AP-42, Section 7.1, Table 7.1-2 (diesel/distilate)

AP-42, Section 7.1, Table 7.1-2	M_V (diesel)=	130	lb/lb-mol
AP-42, Section 7.1, Note below equation 1-37	P_{VA} (diesel)=	0.006	psi
AP-42, Section 7.1, Note below equation 1-37	K_P (diesel)=	1	
	K_B =	1	

AP-42, Section 7.1, Table 7.1-2 (methanol)

AP-42, Section 7.1, Table 7.1-3	M_V (MeOH)=	32.04	lb/lb-mol
AP-42, Section 7.1, Note below equation 1-37	P_{VA} (MeOH)=	1.476	psi
AP-42, Section 7.1, Note below equation 1-37	K_P (MeOH)=	1	
	K_B =	1	

[4] K_N is equal to 1 for 36 or less turnovers per year

Table D2-7. Potential Emissions (Before Controls/Limitations) - Sulfur Dioxide (SO_2)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Potential Fuel [1] Sulfur Content	Factor Reference	Emission Factor [2,3]	Potential Annual Operation	Potential Annual Emissions [3]
ID	Description	Rating/Capacity						
Significant Emission Units								
420a	Generator	1,971 hp	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	8,760 hr/hr	0.09 tpy
421a	Generator	1,971 hp	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	8,760 hr/hr	0.09 tpy
500	Turbine	11,862 kW	Fuel Gas	250 ppmv	Mass Balance	42.1 lb/MMscf	8,760 hr/hr	23.0 tpy
501	Turbine	11,862 kW	Fuel Gas	250 ppmv	Mass Balance	42.1 lb/MMscf	8,760 hr/hr	23.0 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	250 ppmv	Mass Balance	42.1 lb/MMscf	8,760 hr/hr	6.1 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	250 ppmv	Mass Balance	42.1 lb/MMscf	8,760 hr/hr	0.2 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	250 ppmv	Mass Balance	42.1 lb/MMscf	8,760 hr/hr	5.4 tpy
Drill Rig Equipment								
1	Rig Engines	Various	Diesel/Fuel Gas	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	950,000 gallons	0.1 tpy
8	Rig Boilers and Heaters	Various	Diesel/Fuel Gas					
Significant Emission Units - Estimated Potential Emissions - SO_2								**58.1 tpy**
Insignificant Emission Units								
417	Diesel Tank	15,000 barrels	NA	NA	NA	NA	8,760 hr/yr	0 tpy
418	Methanol Tank	450 barrels	NA	NA	NA	NA	8,760 hr/yr	0 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	NA	AP-42, Table 2.1-12	2.5 lb/ton	8,760 hr/yr	0.4 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	NA	AP-42, Table 2.1-12	2.5 lb/ton	8,760 hr/yr	0.5 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	8,760 hr/yr	0.007 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	8,760 hr/yr	0.007 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	8,760 hr/yr	0.007 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	8,760 hr/yr	0.007 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	8,760 hr/yr	0.04 tpy
Insignificant Emission Units - Estimated Potential Emissions - SO_2								**0.9 tpy**
Total Estimated Potential Emissions - SO_2								**59.0 tpy**

Notes:

[1] Diesel fuel shall not exceed a maximum sulfur of 15 ppmw, per Condition 14, AQ0417TVP03. Fuel gas and produced gas H_2S content shall not exceed 250 ppmv, per Condition 13, AQ0417TVP03.

[2] Mass balance:

For fuel gas, the SO_2 emission factor is calculated based on the natural gas sulfur content.

ppmv H_2S = scf H_2S per MMscf fuel gas

Molar ratio: 1 mol H_2S = 1 mol S = 1 mol SO_2

Sulfur content of Natural Gas = 0.75 ppmv H_2S = 0.75 scf H_2S/MMscf fuel

SO_2 Emission Factor, lb/MMscf = (scf H_2S/MMscf fuel) x (64 lb SO_2/1mol S) / (379.9 scf/mol at STP)

For diesel units, the SO_2 emission factor is calculated based on the sulfur content in diesel fuel

Molar mass ratio is 32 lb S/mol : 64 lb SO_2/mol; Stoichiometry: 1 mol S = 1 mol SO_2

SO_2 Emission Factor, lb/gal = (Molar mass ratio, 2 lb SO_2: 1 lb S) x (weight % S in fuel) x (density of fuel, lb/gal) / 100%

[3] Conversions and parameters.

Diesel density (AP-42, Appendix A)	7.05	lb/gal
Engine heat rate (AP-42, Section 3.3)	7,000	Btu/hp-hr
Diesel Heat Content (AP-42, Appendix A)	137,000	Btu/gal
Vendor turbine Heat Rate	10,710	Btu/kW-hr
Average gross heating value (AP-42, Section 1.4)	1,020	Btu/scf

Table D2-8. Potential Emissions (Before Controls/Limitations) - Greenhouse Gas Carbon Dioxide Equivalent (CO_2e)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Potential Annual Greenhouse Gas Emissions (tpy)				
ID	Description	Rating/Capacity		CO_2	CH_4	N_2O	GHG Mass	GHG CO_2e
Significant Emission Units								
420a	Generator	1,971 hp	Diesel	9,853	4.0E-01	8.0E-02	9,854	9,887
421a	Generator	1,971 hp	Diesel					
500	Turbine	11,862 kW	Fuel Gas	65,091	1.23	0.123	65,092	65,158
501	Turbine	11,862 kW	Fuel Gas	65,091	1.23	0.123	65,092	65,158
503	Production Heater	34 MMBtu/hr	Fuel Gas	17,420	0.33	0.033	17,420	17,438
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	687	0.01	0.001	687	687
507	Flare	258 MMscf/yr	Fuel Gas and Produced Gas	15,386	0.29	0.029	15,386	15,402
Drill Rig Equipment								
1	Rig Engines	Various	Diesel/Fuel Gas	10,610.6	4.30E-01	8.61E-02	10,611.1	10,647.0
8	Rig Boilers and Heaters	Various	Diesel/Fuel Gas					
Significant Emission Units - Estimated Potential Emissions - Greenhouse Gases							**184,142**	**184,377**
Insignificant Emission Units								
417	Diesel Tank	15,000 barrels	NA	0	0	0	0	0
418	Methanol Tank	450 barrels	NA	0	0	0	0	0
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	305	0.1	0.01	305	312
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	370	0.1	0.02	371	379
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	714	0.03	0.006	714	717
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	714	0.03	0.006	714	717
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	714	0.03	0.006	714	717
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	714	0.03	0.006	714	717
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	4285	0.2	0.03	4,285	4,300
Insignificant Emission Units - Estimated Potential Emissions - Greenhouse Gases							**7,818**	**7,857**
Total Estimated Potential Emissions - Greenhouse Gases							**191,960**	**192,234**

Table D2-9. Potential Emissions (Before Controls/Limitations) - Carbon Dioxide (CO_2)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel	Factor	Emission	Potential Annual	Potential Annual
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions [1]
Significant Emission Units							
420a	Generator	1,971 hp	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hr/hr	9,853 tpy
421a	Generator	1,971 hp	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hr/hr	9,853 tpy
500	Turbine	11,862 kW	Fuel Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/hr	65,091 tpy
501	Turbine	11,862 kW	Fuel Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/hr	65,091 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/hr	17,420 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/hr	687 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/hr	15,386 tpy
Drill Rig Equipment							
1	Rig Engines	Various	Diesel/Fuel Gas	40 CFR 98, Table C-1	73.96 kg/MMBtu	950,000 gallons	10,611 tpy [2]
8	Rig Boilers and Heaters	Various	Diesel/Fuel Gas				
						Significant Emission Units - Estimated Potential Emissions - CO_2	**193,991 tpy**
Insignificant Emission Units							
417	Diesel Tank	15,000 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
418	Methanol Tank	450 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	40 CFR 98, Table C-1	90.7 kg/MMBtu	8,760 hr/yr	305 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	40 CFR 98, Table C-1	90.7 kg/MMBtu	8,760 hr/yr	370 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hr/yr	714 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hr/yr	714 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hr/yr	714 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hr/yr	714 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hr/yr	4,285 tpy
						Insignificant Emission Units - Estimated Potential Emissions - CO_2	**7,817 tpy**
						Total Estimated Potential Emissions- CO_2	**201,808 tpy**

Notes:

[1] Conversions and parameters.

Diesel Heat Content (AP-42, Appendix A)	137,000	Btu/gal
Engine heat rate (AP-42, Section 3.3)	7,000	Btu/hp-hr
Vendor turbine Heat Rate	10,710	Btu/kW-hr
Average gross heating value (AP-42, Section 1.4)	1,020	Btu/scf
Solid waste heat value (40 CFR 98, Table C-1)	9.95	MMBtu/ton

[2] Calculations are performed for boilers and heaters.

Table D2-10. Potential Emissions (Before Controls/Limitations) - Methane (CH_4)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Factor Reference	Emission Factor	Potential Annual Operation	Potential Annual Emissions [1]
ID	Description	Rating/Capacity					
Significant Emission Units							
420a	Generator	1,971 hp	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hr/hr	0.4 tpy
421a	Generator	1,971 hp	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hr/hr	0.4 tpy
500	Turbine	11,862 kW	Fuel Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hr/hr	1.2 tpy
501	Turbine	11,862 kW	Fuel Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hr/hr	1.2 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hr/hr	0.3 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hr/hr	0.01 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hr/hr	0.3 tpy
Drill Rig Equipment							
1	Rig Engines	Various	Diesel/Fuel Gas	45 CFR 98, Table C-2	0.003 kg/MMBtu	950,000 gallons	0.4 tpy [2]
8	Rig Boilers and Heaters	Various	Diesel/Fuel Gas				
Significant Emission Units - Estimated Potential Emissions - CH_4							**4.3 tpy**
Insignificant Emission Units							
417	Diesel Tank	15,000 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
418	Methanol Tank	450 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	40 CFR 98, Table C-2	0.032 kg/MMBtu	8,760 hr/yr	0.1 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	40 CFR 98, Table C-2	0.032 kg/MMBtu	8,760 hr/yr	0.1 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hr/yr	0.03 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hr/yr	0.03 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hr/yr	0.03 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hr/yr	0.03 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hr/yr	0.2 tpy
Insignificant Emission Units - Estimated Potential Emissions - CH_4							**0.5 tpy**
Total Estimated Potential Emissions - CH_4							**4.8 tpy**

Notes:

[1] Conversions and parameters.

Diesel Heat Content (AP-42, Appendix A)	137,000	Btu/gal
Engine heat rate (AP-42, Section 3.3)	7,000	Btu/hp-hr
Vendor turbine Heat Rate	10,710	Btu/kW-hr
Average gross heating value (AP-42, Section 1.4)	1,020	Btu/scf
Solid waste heat value (40 CFR 98, Table C-1)	9.95	MMBtu/ton

[2] Calculations are performed for boilers and heaters.

Table D2-11. Potential Emissions (Before Controls/Limitations) - Nitrous Oxide (N_2O)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel	Factor	Emission	Potential Annual	Potential Annual
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions [1]
Significant Emission Units							
420a	Generator	1,971 hp	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hr/hr	0.08 tpy
421a	Generator	1,971 hp	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hr/hr	0.08 tpy
500	Turbine	11,862 kW	Fuel Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hr/hr	0.1 tpy
501	Turbine	11,862 kW	Fuel Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hr/hr	0.1 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hr/hr	0.03 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hr/hr	0.001 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hr/hr	0.03 tpy
Drill Rig Equipment							
1	Rig Engines	Various	Diesel/Fuel Gas	40 CFR 98, Table C-2	0.0006 kg/MMBtu	950,000 gallons	0.09 tpy [2]
8	Rig Boilers and Heaters	Various	Diesel/Fuel Gas				
Significant Emission Units - Estimated Potential Emissions - N_2O							**0.6 tpy**
Insignificant Emission Units							
417	Diesel Tank	15,000 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
418	Methanol Tank	450 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	40 CFR 98, Table C-2	0.0042 kg/MMBtu	8,760 hr/yr	0.01 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	40 CFR 98, Table C-2	0.0042 kg/MMBtu	8,760 hr/yr	0.02 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hr/yr	0.006 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hr/yr	0.006 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hr/yr	0.006 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hr/yr	0.006 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hr/yr	0.03 tpy
Insignificant Emission Units - Estimated Potential Emissions - N_2O							**0.09 tpy**
Total Estimated Potential Emissions - N_2O							**0.6 tpy**

Notes:

[1] Conversions and parameters.

Diesel Heat Content (AP-42, Appendix A)	137,000	Btu/gal
Engine heat rate (AP-42, Section 3.3)	7,000	Btu/hp-hr
Vendor turbine Heat Rate	10,710	Btu/kW-hr
Average gross heating value (AP-42, Section 1.4)	1,020	Btu/scf
Solid waste heat value (40 CFR 98, Table C-1)	9.95	MMBtu/ton

[2] Calculations are performed for boilers and heaters.

Table D2-12. Potential Emissions (Before Controls/Limitations) - Hazardous Air Pollutants (HAP)
Savant Alaska, LLC - Badami Development Facility

Hazardous Air Pollutant	Diesel Engines >600 hp	Natural Gas Turbines	Natural Gas Boilers/Heaters	Flares	Diesel Boilers/Heaters	Insignificant Incinerators	Insignificant Diesel Heaters	Total HAP Emissions[1]
Acetaldehyde	3.05E-03	4.45E-02	----	5.54E-03	----	----	----	**5.31E-02**
Acrolein	9.52E-04	7.12E-03	----	1.29E-03	----	----	----	**9.36E-03**
Benzene	9.38E-02	1.34E-02	3.19E-04	2.05E-02	1.02E-04	----	6.84E-05	**1.28E-01**
1,3-Butadiene	----	4.79E-04	----	----	----	----	----	**4.79E-04**
1,4-Dichlorobenzene(p)	----	----	1.82E-04	----	----	----	----	**1.82E-04**
Ethyl benzene	----	3.56E-02	----	1.86E-01	3.02E-05	----	2.03E-05	**2.22E-01**
Formaldehyde	9.5E-03	7.9E-01	1.1E-02	1.5E-01	0	----	1.1E-02	**9.88E-01**
N-Hexane	----	----	2.7E-01	1.3E+00	----	----	----	**1.60E+00**
Hydrochloric acid	----	----	----	----	----	7.30E-01	----	**7.30E-01**
Polycyclic Organic Matter (POM)	2.56E-02	2.45E-03	1.08E-04	1.81E-03	1.57E-03	----	1.06E-03	**3.26E-02**
Acenaphthene	5.66E-04	----	2.73E-06	----	1.20E-07	----	8.09E-08	**5.69E-04**
Acenaphthylene	1.12E-03	----	2.73E-07	----	1.00E-05	----	6.75E-06	**1.13E-03**
Anthracene	1.49E-04	----	3.64E-07	----	5.80E-07	----	3.90E-07	**1.50E-04**
Benzo(a)anthracene	7.52E-05	----	2.73E-07	----	1.90E-06	----	1.28E-06	**7.86E-05**
Benzo(a)pyrene	----	----	1.82E-07	----	----	----	----	**1.82E-07**
Benzo(b)fluoranthene	1.34E-04	----	2.73E-07	----	----	----	----	**1.34E-04**
Benzo(g,h,i)perylene	----	----	1.82E-07	----	----	----	----	**1.82E-07**
Benzo(g,h,l)perylene	----	----	----	----	1.07E-06	----	7.23E-07	**1.80E-06**
Benzo(k)fluoranthene	----	----	2.73E-07	----	----	----	----	**2.73E-07**
Chrysene	----	----	2.73E-07	----	1.13E-06	----	7.61E-07	**2.16E-06**
Dibenz(a,h)anthracene	----	----	1.82E-07	----	7.93E-07	----	5.34E-07	**1.51E-06**
Fluorene	----	----	4.25E-07	----	2.12E-06	----	1.43E-06	**3.98E-06**
Fluoranthene	----	----	4.55E-07	----	2.30E-06	----	1.55E-06	**4.30E-06**
Indeno(1,2,3-cd)pyrene	----	----	----	----	1.02E-06	----	6.84E-07	**1.70E-06**
2-Methylnaphthalene	----	----	3.64E-06	----	----	----	----	**3.64E-06**
Naphthalene	----	1.45E-03	9.26E-05	1.42E-03	5.37E-04	----	3.61E-04	**3.86E-03**
Phenanthrene	----	----	2.58E-06	----	4.99E-06	----	3.36E-06	**1.09E-05**
Pyrene	----	----	7.59E-07	----	2.02E-06	----	1.36E-06	**4.14E-06**
Propylene oxide	----	3.23E-02	----	----	----	----	----	**3.23E-02**
Toluene	3.40E-02	1.45E-01	5.16E-04	7.48E-03	2.95E-03	----	1.98E-03	**1.92E-01**
1,1,1-Trichloroethane	----	----	----	----	1.12E-04	----	7.55E-05	**1.88E-04**
Xylenes	2.33E-02	7.12E-02	----	3.74E-03	5.18E-05	----	3.48E-05	**9.84E-02**
Arsenic Compounds	----	----	----	----	2.60E-04	2.27E-04	1.75E-04	**6.63E-04**

Table D2-12. Potential Emissions (Before Controls/Limitations) - Hazardous Air Pollutants (HAP)
Savant Alaska, LLC - Badami Development Facility

Hazardous Air Pollutant	Diesel Engines >600 hp	Natural Gas Turbines	Natural Gas Boilers/Heaters	Flares	Diesel Boilers/Heaters	Insignificant Incinerators	Insignificant Diesel Heaters	Total HAP Emissions[1]
Beryllium Compounds	----	----	----	----	1.95E-04	----	1.31E-04	**3.27E-04**
Cadmium Compounds	----	----	----	----	1.95E-04	8.18E-04	1.31E-04	**1.14E-03**
Chromium Compounds	----	----	----	----	1.95E-04	1.12E-03	1.31E-04	**1.45E-03**
Lead Compounds	----	----	7.74E-02	----	5.86E-04	----	3.94E-04	**7.84E-02**
Manganese Compounds	----	----	----	----	3.90E-04	----	2.63E-04	**6.53E-04**
Mercury Compounds	----	----	----	----	1.95E-04	1.90E-03	1.31E-04	**2.23E-03**
Nickel Compounds	----	----	----	----	1.95E-04	1.87E-03	1.31E-04	**2.20E-03**
Selenium Compounds	----	----	----	----	9.76E-04	----	6.57E-04	**1.63E-03**
Dioxins/Furans	----	----	----	----	----	9.98E-07	----	**9.98E-07**
Total HAPs - Maximum Individual HAP	**9.4E-02**	**0.8**	**0.3**	**1.3**	**0**	**0.7**	**0.01**	**1.6**
Total VOC HAP Emissions	**1.9E-01**	**1.1**	**0.3**	**1.7**	**0**	**0**	**0.01**	**3.4**
Total HAPs Emissions	**1.9E-01**	**1.1**	**0.4**	**1.7**	**0**	**0.7**	**0.02**	**4.2**

Notes:
[1] See individual emissions unit category emissions calculations for details on methodology and assumptions in the electronic copy.

Table D2-13. Potential Emissions (Before Controls/Limitations) - Hazardous Air Pollutants (HAP)
Diesel Engines Greater Than or Equal to 600 Horsepower

Maximum Total Heat Input: 241,723.4 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**Emission Factor [2]**	**Estimated Emissions**
75-07-0	Acetaldehyde	2.52E-05 lb/MMBtu	3.05E-03 tpy
107-02-8	Acrolein	7.88E-06 lb/MMBtu	9.52E-04 tpy
71-43-2	Benzene	7.76E-04 lb/MMBtu	9.38E-02 tpy
50-00-0	Formaldehyde	7.89E-05 lb/MMBtu	9.54E-03 tpy
108-88-3	Toluene	2.81E-04 lb/MMBtu	3.40E-02 tpy
1330-20-7	Xylenes	1.93E-04 lb/MMBtu	2.33E-02 tpy
N/A	Polycyclic Organic Matter (POM)	2.12E-04 lb/MMBtu	2.56E-02 tpy
	Polycyclic aromatic compounds(PAH)		
208-96-8	Acenaphthene	4.68E-06 lb/MMBtu	5.66E-04 tpy
83-32-9	Acenaphthylene	9.23E-06 lb/MMBtu	1.12E-03 tpy
120-12-7	Anthracene	1.23E-06 lb/MMBtu	1.49E-04 tpy
56-55-3	Benzo(a)anthracene	6.22E-07 lb/MMBtu	7.52E-05 tpy
205-99-2	Benzo(b)fluoranthene	1.11E-06 lb/MMBtu	1.34E-04 tpy
207-08-9	Benzo(k)fluoranthene	2.18E-07 lb/MMBtu	2.63E-05 tpy
50-32-8	Benzo(a)pyrene	2.57E-07 lb/MMBtu	3.11E-05 tpy
191-24-2	Benzo(g,h,l)perylene	5.56E-07 lb/MMBtu	6.72E-05 tpy
218-01-9	Chrysene	1.53E-06 lb/MMBtu	1.85E-04 tpy
53-70-3	Dibenz(a,h)anthracene	3.46E-07 lb/MMBtu	4.18E-05 tpy
206-44-0	Fluoranthene	4.03E-06 lb/MMBtu	4.87E-04 tpy
86-73-7	Fluorene	1.28E-05 lb/MMBtu	1.55E-03 tpy
193-39-5	Indeno(1,2,3-cd)pyrene	4.14E-07 lb/MMBtu	5.00E-05 tpy
91-20-3	Naphthalene	1.30E-04 lb/MMBtu	1.57E-02 tpy
85-01-8	Phenanthrene	4.08E-05 lb/MMBtu	4.93E-03 tpy
129-00-0	Pyrene	3.71E-06 lb/MMBtu	4.48E-04 tpy

Total Potential HAP Emissions: 1.90E-01 tpy

[1] Total fuel use based on maximum full-time operation as noted below:

EU ID 420a	Generator	1,971 hp	8,760 hr/hr
EU ID 420b	Generator	1,971 hp	8,760 hr/hr

Potential Heat Input: 241,723 MMBtu/yr

Total Potential Heat Input: 241,723 MMBtu/yr

Engine heat rate (AP-42, Section 3.3) 7,000 Btu/hp-hr

[2] Reference: AP-42, Tables 3.4-3 and 3.4-4.

Table D2-14. Potential Emissions (Before Controls/Limitations) - Hazardous Air Pollutants (HAP)
Natural Gas Fired Turbines

Maximum Total Heat Input: 2,225,776 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**Emission Factor [2]**	**Estimated Emissions**
106-99-0	1,3-Butadiene	4.30E-07 lb/MMBtu	4.79E-04 tpy
75-07-0	Acetaldehyde	4.00E-05 lb/MMBtu	4.45E-02 tpy
107-02-8	Acrolein	6.40E-06 lb/MMBtu	7.12E-03 tpy
71-43-2	Benzene	1.20E-05 lb/MMBtu	1.34E-02 tpy
100-41-4	Ethyl benzene	3.20E-05 lb/MMBtu	3.56E-02 tpy
50-00-0	Formaldehyde	7.10E-04 lb/MMBtu	7.90E-01 tpy
91-20-3	Naphthalene	1.30E-06 lb/MMBtu	1.45E-03 tpy
	Polycyclic Organic Matter (POM)	2.20E-06 lb/MMBtu	2.45E-03 tpy
	Polycyclic aromatic compounds(PAH)	2.20E-06 lb/MMBtu	
75-56-9	Propylene oxide	2.90E-05 lb/MMBtu	3.23E-02 tpy
108-88-3	Toluene	1.30E-04 lb/MMBtu	1.45E-01 tpy
1330-20-7	Xylenes	6.40E-05 lb/MMBtu	7.12E-02 tpy

Total Potential HAP Emissions: 1.14 tpy

Notes:

[1] Total fuel use based on maximum full-time operation as noted below:

EU ID 500	Turbine	11,862 kW	8,760	hr/yr
EU ID 501	Turbine	11,862 kW	8,760	hr/yr

Potential Heat Input: 2,225,776 MMBtu/yr, operating

Total Potential Heat Input: 2,225,776 MMBtu/yr

Vendor Turbine Heat Rate: 10,710 Btu/kW-hr

[2] Reference: AP-42, Tables 3.1-3.

Table D2-15. Potential Emissions (Before Controls/Limitations) - Hazardous Air Pollutants (HAP)
Natural Gas Fired Heaters

Maximum Total Heat Input: 309,578 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**Emission Factor [2,3]**	**Estimated Emissions**
106-46-7	1,4-Dichlorobenzene(p)	1.20E-03 lb/MMscf	1.82E-04 tpy
71-43-2	Benzene	2.10E-03 lb/MMscf	3.19E-04 tpy
50-00-0	Formaldehyde	7.52E-02 lb/MMscf	1.14E-02 tpy
	Lead Compounds	5.00E-04 lb/MMscf	7.74E-02 tpy
110-54-3	N-Hexane	1.8 lb/MMscf	2.73E-01 tpy
	Polycyclic Organic Matter (POM)	7.14E-04 lb/MMscf	1.08E-04 tpy
	Polycyclic aromatic compounds(PAH)		
91-57-6	2-Methylnaphthalene	2.40E-05 lb/MMscf	3.64E-06 tpy
83-32-9	Acenaphthene	1.80E-05 lb/MMscf	2.73E-06 tpy
203-96-8	Acenaphthylene	1.80E-06 lb/MMscf	2.73E-07 tpy
120-12-7	Anthracene	2.40E-06 lb/MMscf	3.64E-07 tpy
56-55-3	Benzo(a)anthracene	1.80E-06 lb/MMscf	2.73E-07 tpy
205-99-2	Benzo(b)fluoranthene	1.80E-06 lb/MMscf	2.73E-07 tpy
207-08-9	Benzo(k)fluoranthene	1.80E-06 lb/MMscf	2.73E-07 tpy
50-32-8	Benzo(a)pyrene	1.20E-06 lb/MMscf	1.82E-07 tpy
191-24-2	Benzo(g,h,i)perylene	1.20E-06 lb/MMscf	1.82E-07 tpy
218-01-9	Chrysene	1.80E-06 lb/MMscf	2.73E-07 tpy
53-70-3	Dibenz(a,h)anthracene	1.20E-06 lb/MMscf	1.82E-07 tpy
	7,12-dimethylbenzanthracene	1.60E-05 lb/MMscf	2.43E-06 tpy
206-44-0	Fluoranthene	3.00E-06 lb/MMscf	4.55E-07 tpy
86-73-7	Fluorene	2.80E-06 lb/MMscf	4.25E-07 tpy
193-39-5	Ideno(1,2,3-cd)pyrene	1.80E-06 lb/MMscf	2.73E-07 tpy
56-49-5	3-methylcholanthrene	1.80E-06 lb/MMscf	2.73E-07 tpy
91-20-3	Naphthalene	6.10E-04 lb/MMscf	9.26E-05 tpy
85-01-8	Phenanthrene	1.70E-05 lb/MMscf	2.58E-06 tpy
129-00-0	Pyrene	5.00E-06 lb/MMscf	7.59E-07 tpy
108-88-3	Toluene	3.40E-03 lb/MMscf	5.16E-04 tpy
		Total Potential HAP Emissions:	**0.36 tpy**

[1] Total fuel use based on maximum full-time operationas noted below:

EU ID 503	Production Heater	34.0 MMBtu/hr			
	Potential Heat Input:		297,840 MMBtu/yr, operating	8,760	hr/yr
EU ID 505	TEG Reboiler	1.34 MMBtu/hr			
	Potential Heat Input:		11,738 MMBtu/yr, operating	8,760	hr/yr
	Total Potential Heat Input:		**309,578 MMBtu/yr**		

[2] Reference: AP-42, Tables 1.4-2 and 1.4-3.

[3] Average gross heating value (AP-42, Section 1.4) 1,020 Btu/scf

Table D2-16. Potential Emissions (Before Controls/Limitations) - Hazardous Air Pollutants (HAP)
Diesel Fired Heaters

Maximum Total Heat Input: 130,150 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**Emission Factor [2,3]**	**Estimated Emissions**
	Arsenic Compounds	4.00E-06 lb/MMBtu	2.60E-04 tpy
71-43-2	Benzene	1.56E-06 lb/MMBtu	1.02E-04 tpy
	Beryllium Compounds	3.00E-06 lb/MMBtu	1.95E-04 tpy
	Cadmium Compounds	3.00E-06 lb/MMBtu	1.95E-04 tpy
	Chromium Compounds	3.00E-06 lb/MMBtu	1.95E-04 tpy
100-41-4	Ethyl benzene	4.64E-07 lb/MMBtu	3.02E-05 tpy
50-00-0	Formaldehyde	2.41E-04 lb/MMBtu	1.57E-02 tpy
	Lead Compounds	9.00E-06 lb/MMBtu	5.86E-04 tpy
	Manganese Compounds	6.00E-06 lb/MMBtu	3.90E-04 tpy
	Mercury Compounds	3.00E-06 lb/MMBtu	1.95E-04 tpy
	Nickel Compounds	3.00E-06 lb/MMBtu	1.95E-04 tpy
	Polycyclic Organic Matter (POM)	2.41E-05 lb/MMBtu	1.57E-03 tpy
	Polycyclic aromatic compounds(PAH)		
83-32-9	Acenaphthylene	1.54E-07 lb/MMBtu	1.00E-05 tpy
208-96-8	Acenaphthene	1.85E-09 lb/MMBtu	1.20E-07 tpy
120-12-7	Anthracene	8.91E-09 lb/MMBtu	5.80E-07 tpy
56-55-3	Benzo(a)anthracene	2.93E-08 lb/MMBtu	1.90E-06 tpy
205-99-2/207-08-9	Benzo(b,k)fluoranthene	1.08E-08 lb/MMBtu	7.03E-07 tpy
191-24-2	Benzo(g,h,l)perylene	1.65E-08 lb/MMBtu	1.07E-06 tpy
218-01-9	Chrysene	1.74E-08 lb/MMBtu	1.13E-06 tpy
53-70-3	Dibenz(a,h)anthracene	1.22E-08 lb/MMBtu	7.93E-07 tpy
206-44-0	Fluoranthene	3.53E-08 lb/MMBtu	2.30E-06 tpy
86-73-7	Fluorene	3.26E-08 lb/MMBtu	2.12E-06 tpy
193-39-5	Indeno(1,2,3-cd)pyrene	1.56E-08 lb/MMBtu	1.02E-06 tpy
91-20-3	Naphthalene	8.25E-06 lb/MMBtu	5.37E-04 tpy
85-01-8	Phenanthrene	7.66E-08 lb/MMBtu	4.99E-06 tpy
129-00-0	Pyrene	3.10E-08 lb/MMBtu	2.02E-06 tpy
	Selenium Compounds	1.50E-05 lb/MMBtu	9.76E-04 tpy
108-88-3	Toluene	4.53E-05 lb/MMBtu	2.95E-03 tpy
71-55-6	1,1,1-Trichloroethane	1.72E-06 lb/MMBtu	1.12E-04 tpy
1330-20-7	Xylenes	7.96E-07 lb/MMBtu	5.18E-05 tpy

Total Potential HAP Emissions: 2.37E-02 tpy

[1] Total fuel use based on maximum full-time operation as noted below:

EU ID I	Rig Boilers and Heaters	950,000 gallons	
	Potential Heat Input:		130,150 MMBtu/yr
	Total Potential Heat Input:		**130,150 MMBtu/yr**

[2] Reference: AP-42, Tables 1.3-8, 1.3-9, and 1.3-10.

[3] Diesel Fuel Heat Content (AP-42, Appendix A): 137,000 Btu/gal

Table D2-17. Potential Emissions (Before Controls/Limitations) - Hazardous Air Pollutants (HAP)
Flares

Maximum Total Heat Input: 257.9 MMscf/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**Emission Factor [2,3]**	**Estimated Emissions**
	Flared Gas:		
75-07-0	Acetaldehyde	0.043 lb/MMscf	5.54E-03 tpy
107-02-8	Acrolein	0.010 lb/MMscf	1.29E-03 tpy
71-43-2	Benzene	0.159 lb/MMscf	2.05E-02 tpy
100-41-4	Ethyl benzene	1.444 lb/MMscf	1.86E-01 tpy
50-00-0	Formaldehyde	1.169 lb/MMscf	1.51E-01 tpy
110-54-3	N-Hexane	0.029 lb/MMscf	3.74E-03 tpy
91-20-3	Naphthalene	0.011 lb/MMscf	1.42E-03 tpy
108-88-3	Toluene	0.058 lb/MMscf	7.48E-03 tpy
1330-20-7	Xylenes	0.029 lb/MMscf	3.74E-03 tpy
	Polycyclic Organic Matter (POM)	0.014 lb/MMscf	1.81E-03 tpy
	Uncombusted Gas:		
110-54-3	N-Hexane	10.297 lb/MMscf	1.3E+00 tpy

Total Potential HAP Emissions: 1.71 tpy

[1] Total fuel use based on maximum full-time operation as noted below:

EU ID 507 Flare

Potential Consumption: 257,900 Mscf/yr, operating 8,760 hr/yr

Total Potential Heat Input: 257.9 MMscf/yr

[2] Reference: VCAPCD AB 2588 (Flares - Natural Gas)

[3] Flare destruction efficiency estimated at 98%.

[3] October 9, 2017 gas analysis, 0.227 mole percent hexane plus (0.20 lbs/lb-mol).

Table D2-18. Potential Emissions (Before Controls/Limitations) - Hazardous Air Pollutants (HAP)
Insignificant Incinerators

Maximum Total Heat Input: 679 ton/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**Emission Factor [2]**	**Estimated Emissions**
	Arsenic Compounds	6.69E-04 lb/ton	0.000227092 tpy
	Cadmium Compounds	2.41E-03 lb/ton	8.18E-04 tpy
	Chromium Compounds	3.31E-03 lb/ton	1.12E-03 tpy
7647-01-0	Hydrochloric Acid	2.15E+00 lb/ton	0.73 tpy
	Mercury Compounds	5.60E-03 lb/ton	1.90E-03 tpy
	Nickel Compounds	5.52E-03 lb/ton	1.87E-03 tpy
	Dioxins/Furans	2.94E-06 lb/ton	9.98E-07 tpy

Total Potential HAP Emissions: 0.7 tpy

Notes:

[1] Total incinerated weight based on maximum operation for the following:

422	Smart Ash 100-A Incinerator	0.04 tons/hr			
	Potential Heat Input:		307 tons/yr, operating	8,760	hr/yr
502	Therm-Tec-G-12 Incinerator	85 lb/hr			
	Potential Heat Input:		372 tons/yr, operating	8,760	hr/yr

Total Potential Waste incinerated: 679 ton/yr

[2] Reference: AP-42, Tables 2.1-9, Modular Starved-Air Combustors.

Table D2-19. Potential Emissions (Before Controls/Limitations) - Hazardous Air Pollutants (HAP)
Insignificant Diesel Fired Heaters

Maximum Total Heat Input: 87,600 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations		
CAS No.	**Chemical Name**	**Emission Factor [2,3]**		**Estimated Emissions**
	Arsenic Compounds	4.00E-06	lb/MMBtu	1.75E-04 tpy
71-43-2	Benzene	1.56E-06	lb/MMBtu	6.84E-05 tpy
	Beryllium Compounds	3.00E-06	lb/MMBtu	1.31E-04 tpy
	Cadmium Compounds	3.00E-06	lb/MMBtu	1.31E-04 tpy
	Chromium Compounds	3.00E-06	lb/MMBtu	1.31E-04 tpy
100-41-4	Ethyl benzene	4.64E-07	lb/MMBtu	2.03E-05 tpy
50-00-0	Formaldehyde	2.41E-04	lb/MMBtu	1.06E-02 tpy
	Lead Compounds	9.00E-06	lb/MMBtu	3.94E-04 tpy
	Manganese Compounds	6.00E-06	lb/MMBtu	2.63E-04 tpy
	Mercury Compounds	3.00E-06	lb/MMBtu	1.31E-04 tpy
	Nickel Compounds	3.00E-06	lb/MMBtu	1.31E-04 tpy
	Polycyclic Organic Matter (POM)	2.41E-05	lb/MMBtu	1.06E-03 tpy
	Polycyclic aromatic compounds(PAH)			
83-32-9	Acenaphthylene	1.54E-07	lb/MMBtu	6.75E-06 tpy
208-96-8	Acenaphthene	1.85E-09	lb/MMBtu	8.09E-08 tpy
120-12-7	Anthracene	8.91E-09	lb/MMBtu	3.90E-07 tpy
56-55-3	Benzo(a)anthracene	2.93E-08	lb/MMBtu	1.28E-06 tpy
205-99-2/207-08-9	Benzo(b,k)fluoranthene	1.08E-08	lb/MMBtu	4.73E-07 tpy
191-24-2	Benzo(g,h,l)perylene	1.65E-08	lb/MMBtu	7.23E-07 tpy
218-01-9	Chrysene	1.74E-08	lb/MMBtu	7.61E-07 tpy
53-70-3	Dibenz(a,h)anthracene	1.22E-08	lb/MMBtu	5.34E-07 tpy
206-44-0	Fluoranthene	3.53E-08	lb/MMBtu	1.55E-06 tpy
86-73-7	Fluorene	3.26E-08	lb/MMBtu	1.43E-06 tpy
193-39-5	Indeno(1,2,3-cd)pyrene	1.56E-08	lb/MMBtu	6.84E-07 tpy
91-20-3	Naphthalene	8.25E-06	lb/MMBtu	3.61E-04 tpy
85-01-8	Phenanthrene	7.66E-08	lb/MMBtu	3.36E-06 tpy
129-00-0	Pyrene	3.10E-08	lb/MMBtu	1.36E-06 tpy
NA	Selenium Compounds	1.50E-05	lb/MMBtu	6.57E-04 tpy
108-88-3	Toluene	4.53E-05	lb/MMBtu	1.98E-03 tpy
71-55-6	1,1,1-Trichloroethane	1.72E-06	lb/MMBtu	7.55E-05 tpy
1330-20-7	Xylenes	7.96E-07	lb/MMBtu	3.48E-05 tpy

Total Potential HAP Emissions: 0.02 tpy

[1] Total fuel use based on maximum full-time operation as noted below:

EU 607	Indirect Fire Heater	1	MMBtu/hr		
	Potential Heat Input:			8,760 MMBtu/yr, operating	8,760 hr/yr
EU 608	Indirect Fire Heater	1	MMBtu/hr		
	Potential Heat Input:			8,760 MMBtu/yr, operating	8,760 hr/yr
EU 611	Indirect Fire Heater	1	MMBtu/hr		
	Potential Heat Input:			8,760 MMBtu/yr, operating	8,760 hr/yr
EU 612	Indirect Fire Heater	1	MMBtu/hr		
	Potential Heat Input:			8,760 MMBtu/yr, operating	8,760 hr/yr
NA	Hot Oil Heater	6	MMBtu/hr		
				52,560 MMBtu/yr, operating	8,760 hr/yr

Total Potential Heat Input: 87,600 MMBtu/yr

[2] Reference: AP-42, Tables 1.3.8, 1.3-9, and 1.3-10.

[3] Diesel Fuel Heat Content (AP-42, Appendix A): 137,000 Btu/gal

Table D3-1. Potential Annual Emissions (After Controls/Limitations) Summary
Savant Alaska, LLC - Badami Development Facility

Potential to Emit	Regulated Air Pollutant Emissions (tons per year) [1,2]							
	NO_X	CO	PM_{10}	$PM_{2.5}$ [3]	VOC	SO_2	GHG [4,5]	HAP [6]
Significant	447.8	404.6	13.5	13.5	94.7	56.2	183,999	3.3
Insignificant	3.9	7.6	5.6	5.6	5.4	0.9	4,274	0.7
Total Emissions	**451.6**	**412.2**	**19.1**	**19.1**	**100.1**	**57.1**	**188,273**	**4.1**
Assessable Emissions Total [7,8,9]	**1,040.2**							

Notes:

[1] Emissions are based on maximum allowable operation and permit operating limits, where applicable.

[2] Regulated air pollutant calculations based on AP-42 emission factors, vendor data, source test data, and mass balances as shown in accompanying spreadsheets.

[3] $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions.

[4] GHG emissions are defined as CO_2e emissions. CO_2e is the summation of CO_2, CH_4, and N_2O, applying the global warming potential for each pollutant.

[5] Per 40 CFR 71.2, GHGs are subject to regulation beginning on July 1, 2011.

[6] See individual emissions unit category HAP emissions calculations for details on methodology and assumptions (electronic copy).

[7] HAP emissions are a subset of either VOC emissions or PM_{10} emissions and are excluded from the assessable emissions total to avoid a double payment.

[8] $PM_{2.5}$ emissions are a subset of PM_{10} emissions and are excluded from the assessable emissions total to avoid a double payment.

[9] Assessable emission fees for GHGs have not been established under 18 AAC 50.

Table D3-1. Potential Annual Emissions (After Controls/Limitations) Summary
Savant Alaska, LLC - Badami Development Facility

Potential to Emit	Regulated Air Pollutant Emissions (tons per year) [1,2]							
	NO_X	CO	PM_{10}	$PM_{2.5}$ [3]	VOC	SO_2	GHG [4,5]	HAP [6]
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Total Emissions	**451.6**	**412.2**	**19.1**	**19.1**	**100.1**	**57.1**	**188,273**	**4.1**
Assessable Emissions Total [7,8,9]	**1,040.2**							

Notes:

[1] Emissions are based on maximum allowable operation and permit operating limits, where applicable.

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[8] $PM_{2.5}$ emissions are a subset of PM_{10} emissions and are excluded from the assessable emissions total to avoid a double payment.

[9] Assessable emission fees for GHGs have not been established under 18 AAC 50.

Table D3-2a. Significant Emissions Unit Inventory
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel	Potential Annual	Maximum
ID	Description	Make/Model	Type	Operation	Capacity/Output
420a	Generator	Cummins QSK50-G4	Diesel	800,000 gal/yr [1]	1,971 hp
421a	Generator	Cummins QSK50-G4	Diesel		1,971 hp
500	Turbine	Solar Mars 90	Fuel Gas	8,760 hr/hr	11,862 kW
501	Turbine	Solar Mars 90	Fuel Gas	8,760 hr/hr	11,862 kW
503	Production Heater	NATCO	Fuel Gas	8,760 hr/hr	34 MMBtu/hr
505	TEG Reboiler	NATCO	Fuel Gas	8,760 hr/hr	1.34 MMBtu/hr
507	Flare	Mac Injector 100 Series	Fuel Gas and Produced Gas	152 MMscf/yr [2]	257.9 MMscf/yr
Drill Rig Equipment					
1	Rig Engines	Various	Diesel/Fuel Gas	950,000 gal/yr [3]	Various
8	Rig Boilers and Heaters	Various	Diesel/Fuel Gas		Various

Notes:

[1] Title V Permit AQ0417TVP03 Condition 15 limits the operation of EU IDs 420a and 421a to 800,000 gallons of liquid fuel during any 12 consecutive month period.

[2] Title V Permit AQ0417TVP03 Condition 11 limits the operation of EU ID 507 to 152 MMscf of fuel gas and produced gas during any 12 consecutive month period. Maximum capacity is used for the calculation since the limit does not include pilot and purge gas.

[3] Title V Permit AQ0417TVP03 Condition 16 limits the operation of EU IDs 1 and 8 to 950,000 gallons of liquid fuel during any 12 consecutive month period. Minor Permit AQ0417MSS07, Revision 1 allows for the combustion of either liquid fuel or fuel gas, with the limit based on liquid fuel combustion.

Table D3-2b. Insignificant Emissions Unit Inventory
Savant Alaska, LLC - Badami Development Facility

Emission Unit		Fuel	Rating/Size	Potential Annual
ID	Description	Type		Operation
417	Diesel Tank	NA	15,000 barrels	8,760 hr/yr
418	Methanol Tank	NA	450 barrels	8,760 hr/yr
422	Smart Ash 100-A Incinerator	Oily Waste	0.035 tons/hr	8,760 hr/yr
502	Therm-Tec-G-12 Incinerator	Propane/Fuel Gas	1.6 MMBtu/hr	8,760 hr/yr
		Waste	85.0 lb/hr	8,760 hr/yr
607	Indirect Fire Heater	Diesel	1.0 MMBtu/hr	4,380 hr/yr
608	Indirect Fire Heater	Diesel	1.0 MMBtu/hr	4,380 hr/yr
611	Indirect Fire Heater	Diesel	1.0 MMBtu/hr	4,380 hr/yr
612	Indirect Fire Heater	Diesel	1.0 MMBtu/hr	4,380 hr/yr
NA	Hot Oil Heater	Diesel	6.0 MMBtu/hr	4,380 hr/yr

Notes:

[1] Allowable operation for Intermittently Used Oilfield Support Equipment (IUOSE) estimated at 50 percent of 12 consecutive month period for purposes of estimating emissions.

Table D3-2c. Intermittently Used Oilfield Support Equipment (IUOSE) Inventory
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Maximum Capacity	IUOSE	Non-Road Engine	Use (see below)
Quantity	Description	Make/Model					
1	Grader	Caterpillar 14H	Diesel	215 hp	Yes	Yes	B
1	Loader	Caterpillar 966F	Diesel	218 hp	Yes	Yes	B
1	Excavator	Hitachi XE220LC	Diesel	160 hp	Yes	Yes	B
1	Bobcat	Kubota V2203-E	Diesel	50 hp	Yes	Yes	B
1	Bobcat Skid Steer Loader	Deutz T200	Diesel	72 hp	Yes	Yes	B
1	Loader	Caterpillar 966G	Diesel	439 hp	Yes	Yes	B
1	Ingersoll Rand Pro Pac	Cummins 5.9 SD150D	Diesel	185 hp	Yes	Yes	B
1	Kodiak Snow Blower	Caterpillar C13	Diesel	520 hp	Yes	Yes	B
1	Bulldozer	Caterpillar 3306	Diesel	225 hp	Yes	Yes	B
1	H-Series Guzzler	Caterpillar C10	Diesel	238 hp	Yes	Yes	B
1	Generator (mounted on Guzzler)	Yanmar 3Tne	Diesel	13 hp	Yes	Yes	B
1	Fuel Truck	Detroit 6067E	Diesel	350 hp	Yes	Yes	B
1	Dump Truck	Caterpillar 406	Diesel	380 hp	Yes	Yes	B
1	Box Truck	Caterpillar 3126	Diesel	230 hp	Yes	Yes	B
1	Tucker Snow Vehicle	Cummins QSB3.9	Diesel	130 hp	Yes	Yes	B
1	Argo 750 HDI	Kohler LH 775	Gasoline	31 hp	Yes	Yes	B
1	Genie Zoom Boom	Perkins 1104C-44T	Diesel	99 hp	Yes	Yes	A&B
1	Air Compressor	Deutz TD20111l04w	Diesel	63 hp	Yes	Yes	A&B
1	Triplex Pump	Cummins B3.3	Diesel	85 hp	Yes	Yes	A&B
1	Hot Oil Generator	Kubota D1105	Diesel	21 hp	Yes	Yes	A&B
1	Hot Oil Tractor/Pump	Cummins N-14	Diesel	330 hp	Yes	Yes	A&B
1	Generator (mounted on Guzzler)	Cummins 4BTA 5.9	Diesel	67 hp	Yes	Yes	A&B
1	EU BAD 022 - Hot Oil Heater	Webster Cyclonetic JB2-50-YB110-MR	Diesel	6 MMBtu/hr	Yes	No	A&B
1	EU 603a - Air Compressor	Sullair 200HDPQAi4	Diesel	55 hp	Yes	Yes	A&B
1	EU 600 - Crane	Grove RT635C	Diesel	215 hp	Yes	Yes	A&B
1	EU BAD 034a - Manlift	Perkins 804C	Diesel	63 hp	Yes	Yes	A&B
1	EU 604 - Welder	Bobcat 250	Diesel	38 hp	Yes	Yes	A&B
1	EU BAD 036 - Portable Welder Engine	Miller Bobcat MD#907039	Diesel	20 hp	Yes	Yes	A&B
1	LED Light Plant	Perkins 403D	Diesel	11 hp	Yes	Yes	C
2	EU 601/602 - Light Plants	Unknown	Diesel	12.1 hp	Yes	Yes	C
4	ES700 Indirect Fire Heater Motor (used with EU 607608/611/612)	Kubota D1105	Diesel	13 hp	Yes	Yes	C
1	EU 607 (BAD 028) - Indirect Fire Heater	Tioga ES700 - Heater #1	Diesel	1 MMBtu/hr	Yes	No	C
1	EU 608 (BAD 029) - Indirect Fire Heater	Tioga ES700 - Heater #2	Diesel	1 MMBtu/hr	Yes	No	C
1	EU 611 (BAD 030) - Indirect Fire Heater	Tioga ES700 - Heater #3	Diesel	1 MMBtu/hr	Yes	No	C
1	EU 612 (BAD 031) - Indirect Fire Heater	Tioga ES700 - Heater #4	Diesel	1 MMBtu/hr	Yes	No	C
10	Rig Light Plant	Unknown	Diesel	16 hp, each	Yes	Yes	D
1	Frac Engine	Caterpillar 3512	Diesel	1,800 hp	Yes	Yes	D
1	Cement Pump Van Onan	Unknown	Diesel	325 hp	Yes	Yes	D
1	Cement Batch Mixer Onan	Unknown	Diesel	34 hp	Yes	Yes	D
1	Slickline Generator	Unknown	Diesel	31 hp	Yes	Yes	D
1	Slickline Powerpack	John Deere	Diesel	120 hp	Yes	Yes	D
1	E-Line Logger	Unknown	Diesel	310 hp	Yes	Yes	D
1	E-Line Grease Skid	Unknown	Diesel	90 hp	Yes	Yes	D
1	E-Line Spare Generator	Unknown	Diesel	50 hp	Yes	Yes	D
1	CTU Onan	Unknown	Diesel	34 hp	Yes	Yes	D
1	CTU Power Pack	Unknown	Diesel	425 hp	Yes	Yes	D
1	CTU Tractor/Pump	Unknown	Diesel	450 hp	Yes	Yes	D

Uses:

A - Oil Well Servicing and Maintenance

B - General Oilfield Maintenance for Pipelines, Roads, and Other Existing Infrastructure.

C - Oil Well Servicing and General Oilfield Maintenance for Pipelines, Roads, and Other Existing Infrastructure. Units are in storage and used in winter months as needed.

D - Oil Well Servicing and Maintenance, contractor equipment not permanently onsite (ratings are estimated).

Table D3-3. Potential Emissions (After Controls/Limitations) - Oxides of Nitrogen (NO_X)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Factor Reference	Emission Factor	Potential Annual Operation	Potential Annual Emissions [1]
ID	Description	Rating/Capacity					
Significant Emission Units							
420a	Generator	1,971 hp	Diesel	Source Test	0.414 lb/gal	800,000 gal/yr	165.6 tpy
421a	Generator	1,971 hp	Diesel	Source Test			
500	Turbine	11,862 kW	Fuel Gas	AQ0417TVP03, Cond. 17.1b(i)	28.4 lb/hr	8,760 hr/hr	124.4 tpy
501	Turbine	11,862 kW	Fuel Gas	AQ0417TVP03, Cond. 17.1b(i)	28.4 lb/hr	8,760 hr/hr	124.4 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	AQ0417TVP03, Cond. 17.1b(ii)	0.095 lb/MMBtu	8,760 hr/hr	14.1 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	AQ0417TVP03, Cond. 17.1b(iii)	0.08 lb/MMBtu	8,760 hr/hr	0.5 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	AP-42, Table 13.5-1	0.068 lb/MMBtu	257.9 MMscf/yr	9.3 tpy
Drill Rig Equipment							
1	Rig Engines	Various	Diesel/Fuel Gas	AP-42, Table 1.3-1	20 $lb/10^3$ gal	950,000 gal/yr	9.5 tpy [2]
8	Rig Boilers and Heaters	Various	Diesel/Fuel Gas				
Significant Emission Units - Estimated Potential Emissions - NO_X							**447.8 tpy**
Insignificant Emission Units							
417	Diesel Tank	15,000 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
418	Methanol Tank	450 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	AP-42, Table 2.1-12	2 lb/ton	8,760 hr/yr	0.3 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	AP-42, Table 2.1-12	2 lb/ton	8,760 hr/yr	0.4 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	20 $lb/10^3$ gal	4,380 hr/yr	0.3 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	20 $lb/10^3$ gal	4,380 hr/yr	0.3 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	20 $lb/10^3$ gal	4,380 hr/yr	0.3 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	20 $lb/10^3$ gal	4,380 hr/yr	0.3 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	20 $lb/10^3$ gal	4,380 hr/yr	1.9 tpy
Insignificant Emission Units - Estimated Potential Emissions - NO_X							**3.9 tpy**
Total Estimated Potential Emissions - NO_X							**451.6 tpy**

Notes:

[1] Parameters and Conversions:

Gas HHV 2022 Average	1,056 Btu/scf
Diesel Heat Content (AP-42, Appendix A)	137,000 Btu/gal
Engine heat rate (AP-42, Section 3.3)	7,000 Btu/hp-hr

[2] Calculations are performed for boilers and heaters. Nonroad emissions are not included when determining stationary source classification.

Table D3-4. Potential Emissions (After Controls/Limitations) - Carbon Monoxide (CO)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Factor Reference	Emission Factor	Potential Annual Operation	Potential Annual Emissions [1]
ID	Description	Rating/Capacity					
Significant Emission Units							
420a	Generator	1,971 hp	Diesel	Vendor Data	0.48 g/hp-hr	800,000 gal/yr	8.3 tpy
421a	Generator	1,971 hp	Diesel	Vendor Data	0.5 g/hp-hr		
500	Turbine	11,862 kW	Fuel Gas	AQ0417TVP03, Cond. 17.2a(i)	385 lb/hr	8,760 hr/hr	336 tpy [2]
501	Turbine	11,862 kW	Fuel Gas	AQ0417TVP03, Cond. 17.2a(i)	385 lb/hr	8,760 hr/hr	
503	Production Heater	34 MMBtu/hr	Fuel Gas	AQ0417TVP03, Cond. 17.2a(ii)	3.4 lb/hr	8,760 hr/hr	14.9 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	AQ0417TVP03, Cond. 17.2a(iii)	0.15 lb/MMBtu	8,760 hr/hr	0.9 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	AP-42, Table 13.5-2	0.31 lb/MMBtu	257.9 MMscf/yr	42.2 tpy
Drill Rig Equipment							
1	Rig Engines	Various	Diesel/Fuel Gas	AP-42, Table 3.4-1	5 lb/10^3 gal	950,000 gal/yr	2.4 tpy [3]
8	Rig Boilers and Heaters	Various	Diesel/Fuel Gas				
Significant Emission Units - Estimated Potential Emissions - CO							**404.6 tpy**
Insignificant Emission Units							
417	Diesel Tank	15,000 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
418	Methanol Tank	450 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	AP-42, Table 2.1-12	20 lb/ton	8,760 hr/yr	3.1 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	AP-42, Table 2.1-12	20 lb/ton	8,760 hr/yr	3.7 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	5 lb/10^3 gal	4,380 hr/yr	0.1 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	5 lb/10^3 gal	4,380 hr/yr	0.1 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	5 lb/10^3 gal	4,380 hr/yr	0.1 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	5 lb/10^3 gal	4,380 hr/yr	0.1 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1	5 lb/10^3 gal	4,380 hr/yr	0.5 tpy
Insignificant Emission Units - Estimated Potential Emissions - CO							**7.6 tpy**
Total Estimated Potential Emissions - CO							**412.2 tpy**

Notes:

[1] Parameters and Conversions:

Engine heat rate (AP-42, Section 3.3)	7,000 Btu/hp-hr
Gas HHV 2022 Average	1,056 Btu/scf
Diesel Heat Content (AP-42, Appendix A)	137,000 Btu/gal

[2] Combined limit from Condition 17.2b of AQ0417TV03.

[3] Calculations are performed for boilers and heaters. Nonroad emissions are not included when determining stationary source classification.

Table D3-5. Potential Emissions (After Controls/Limitations) - Particulate Matter Less Than 10 Microns (PM_{10})
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Factor Reference	Emission Factor	Potential Annual Operation	Potential Annual Emissions [1]
ID	Description	Rating/Capacity					
Significant Emission Units							
420a	Generator	1,971 hp	Diesel	Vendor Data	0.03 g/hp-hr	800,000 gal/yr	0.5 tpy
421a	Generator	1,971 hp	Diesel	Vendor Data	0.04 g/hp-hr		
500	Turbine	11,862 kW	Fuel Gas	AP-42, Table 3.1-1	0.0066 lb/MMBtu	8,760 hr/hr	3.7 tpy
501	Turbine	11,862 kW	Fuel Gas	AP-42, Table 3.1-1	0.0066 lb/MMBtu	8,760 hr/hr	3.7 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	AP-42, Table 1.4-2	7.6 lb/MMscf	8,760 hr/hr	1.1 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	AP-42, Table 1.4-2	7.6 lb/MMscf	8,760 hr/hr	0.04 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	AP-42, Table 13.5-1	40 µg/L	257.9 MMscf/yr	3.0 tpy
Drill Rig Equipment							
1	Rig Engines	Various	Diesel/Fuel Gas	AP-42, Table 1.3-1 and 1.3-2	3.3 $lb/10^3$ gal	950,000 gal/yr	1.6 tpy [2]
8	Rig Boilers and Heaters	Various	Diesel/Fuel Gas				
Significant Emission Units - Estimated Potential Emissions - PM_{10}							**13.5 tpy**
Insignificant Emission Units							
417	Diesel Tank	15,000 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
418	Methanol Tank	450 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	AP-42, Table 2.1-12	15 lb/ton	8,760 hr/yr	2.3 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	AP-42, Table 2.1-12	15 lb/ton	8,760 hr/yr	2.8 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1 and 1.3-2	3.3 $lb/10^3$ gal	4,380 hr/yr	0.1 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1 and 1.3-2	3.3 $lb/10^3$ gal	4,380 hr/yr	0.1 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1 and 1.3-2	3.3 $lb/10^3$ gal	4,380 hr/yr	0.1 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1 and 1.3-2	3.3 $lb/10^3$ gal	4,380 hr/yr	0.1 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	AP-42, Table 1.3-1 and 1.3-2	3.3 $lb/10^3$ gal	4,380 hr/yr	0.3 tpy
Insignificant Emission Units - Estimated Potential Emissions - PM_{10}							**5.6 tpy**
Total Estimated Potential Emissions - PM_{10}							**19.1 tpy**

Notes:

[1] Parameters and Conversions:

Engine heat rate (AP-42, Section 3.3)	7,000 Btu/hp-hr
Gas HHV 2022 Average	1,056 Btu/scf
Diesel Heat Content (AP-42, Appendix A)	137,000 Btu/gal
Vendor turbine Heat Rate	10,710 Btu/kW-hr
F-Factor (40 CFR 60, Method 19)	8,710 dscf/MMBtu

[2] Calculations are performed for boilers and heaters. Nonroad emissions are not included when determining stationary source classification.

Table D3-6a. Potential Emissions (After Controls/Limitations) - Volatile Organic Compounds (VOCs)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Factor Reference	Emission Factor	Potential Annual Operation	Potential Annual Emissions [1]
ID	Description	Rating/Capacity					
Significant Emission Units							
420a	Generator	1,971 hp	Diesel	Vendor Data	0.09 g/hp-hr	800,000 gal/yr	1.6 tpy
421a	Generator	1,971 hp	Diesel	Vendor Data	0.05 g/hp-hr		
500	Turbine	11,862 kW	Fuel Gas	AP-42, Table 3.1-2a	0.0021 lb/MMBtu	8,760 hr/hr	1.2 tpy
501	Turbine	11,862 kW	Fuel Gas	AP-42, Table 3.1-2a	0.0021 lb/MMBtu	8,760 hr/hr	1.2 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	AP-42, Table 1.4-2	5.5 lb/MMscf	8,760 hr/hr	0.8 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	AP-42, Table 1.4-2	5.5 lb/MMscf	8,760 hr/hr	0.03 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	AP-42 Table 13.5-2	0.66 lb/MMBtu	257.9 MMscf/yr	89.9 tpy
Drill Rig Equipment							
1	Rig Engines	Various	Diesel/Fuel Gas	AP-42, Table 1.3-3	0.34 $lb/10^3$ gal	950,000 gal/yr	0.2 tpy [2]
8	Rig Boilers and Heaters	Various	Diesel/Fuel Gas				
Significant Emission Units - Estimated Potential Emissions - VOC							**94.7 tpy**
Insignificant Emission Units							
417	Diesel Tank	15,000 barrels	NA	See Table D2-6b	NA	8,760 hr/yr	0.08 tpy
418	Methanol Tank	450 barrels	NA	See Table D2-6b	NA	8,760 hr/yr	0.2 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	AP-42, Table 2.1-12	15 lb/ton	8,760 hr/yr	2.3 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	AP-42, Table 2.1-12	15 lb/ton	8,760 hr/yr	2.8 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-3	0.34 $lb/10^3$ gal	4,380 hr/yr	0.01 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-3	0.34 $lb/10^3$ gal	4,380 hr/yr	0.01 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-3	0.34 $lb/10^3$ gal	4,380 hr/yr	0.01 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	AP-42, Table 1.3-3	0.34 $lb/10^3$ gal	4,380 hr/yr	0.01 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	AP-42, Table 1.3-3	0.34 $lb/10^3$ gal	4,380 hr/yr	0.03 tpy
Insignificant Emission Units - Estimated Potential Emissions - VOC							**5.4 tpy**
Total Estimated Potential Emissions - VOC							**100.1 tpy**

Notes:

[1] Parameters and Conversions:

Engine heat rate (AP-42, Section 3.3)	7,000 Btu/hp-hr
Gas HHV 2022 Average	1,056 Btu/scf
Diesel Heat Content (AP-42, Appendix A)	137,000 Btu/gal
Vendor turbine Heat Rate	10,710 Btu/kW-hr

[2] Calculations are performed for boilers and heaters. Nonroad emissions are not included when determining stationary source classification.

Table D3-6b. Potential Emissions (After Controls/Limitations) - Volatile Organic Compounds (VOCs)
Savant Alaska, LLC - Badami Development Facility

Parameter	Factor Reference	Emissions Unit ID	
		417	418
Orientation	NA	Vertical	Horizontal
Contents	NA	ULSD	Methanol
Diameter (ft), D	NA	67	9.3
Effective Diameter (ft), D_E	AP-42, Section 7.1, Equation 1-14	---	21.2
Height (ft), H_S	NA	24	---
Effective Height (ft), H_E	AP-42, Section 7.1, Equation 1-15	---	7.3
Length (ft), L	NA	---	38
Color	NA	White	White
Maximum Liquid Height (ft), H_L	NA	23	---
Capacity (gal)	NA	630,000	18,900
Throughput (gal/yr) [1]	NA	7,560,000	226,800
Turnovers	NA	12	12
Paint Condition	NA	New	New
Standing Loss (L_S) Calculations [2,3]			
K_E	AP-42, Section 7.1, Equation 1-12	0.020	0.020
H_{VO} (ft)	AP-42, Section 7.1, Equation 1-16	1.70	3.7
H_{RO} (ft)	AP-42, Section 7.1, Equation 1-17	0.70	0.10
K_S	AP-42, Section 7.1, Equation 1-21	0.999	0.778
T_{AA} (^oR)	AP-42, Section 7.1, Equation 1-30	470.30	470.30
T_B (^oR)	AP-42, Section 7.1, Equation 1-31	470.73	470.73
T_V (^oR) - uninsulated	AP-42, Section 7.1, Equation 1-33	471.71	471.71
W_V (lb/ft^3)	AP-42, Section 7.1, Equation 1-22	1.54E-04	9.34E-03
L_S (lb/yr)	AP-42, Section 7.1, Equation 1-4	6.8	69.3
Working Loss (L_W) Calculations [3]			
Q (bbl/yr)	NA	180,000	5,400
V_O (ft^3)	AP-42, Section 7.1, Equation 1-39	1,010,520	30,316
K_N [4]	AP-42, Section 7.1, Equation 1-35	1	1
L_W (lb/yr)	AP-42, Section 7.1, Equation 1-35	155.7	283.2
TOTAL VOCs L_T (tpy)	**AP-42, Section 7.1, Equation 1-1**	**0.08**	**0.2**

Note:
[1] Tanks are filled with submerged loading.
[2] Meteorological Inputs (Deadhorse, AK):

	T_{AX} =	16.6	^oF
		476.3	^oR
AP-42, Section 7.1, Table 7.1-6	T_{AN} =	4.6	^oF
		464.3	^oR
AP-42, Section 7.1, Table 7.1-7	α =	0.17	White, New
	I =	838	Btu/ft^2-d

[3] Constants: From the 1995 version of AP-42

AP-42, Section 7.1, Table 7.1-2 (diesel/distilate)			
AP-42, Section 7.1, Table 7.1-2	M_V (diesel)=	130	lb/lb-mol
AP-42, Section 7.1, Note below equation 1-37	P_{VA} (diesel)=	0.006	psi
AP-42, Section 7.1, Note below equation 1-37	K_P (diesel)=	1	
	K_B =	1	
AP-42, Section 7.1, Table 7.1-2 (methanol)			
AP-42, Section 7.1, Table 7.1-3	M_V (MeOH)=	32.04	lb/lb-mol
AP-42, Section 7.1, Note below equation 1-37	P_{VA} (MeOH)=	1.476	psi
AP-42, Section 7.1, Note below equation 1-37	K_P (MeOH)=	1	
	K_B =	1	

[4] K_N is equal to 1 for 36 or less turnovers per year

Table D3-7. Potential Emissions (After Controls/Limitations) - Sulfur Dioxide (SO_2)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Potential Fuel [1] Sulfur Content	Factor Reference	Emission Factor [2,3]	Potential Annual Operation	Potential Annual Emissions [3]
ID	Description	Rating/Capacity						
Significant Emission Units								
420a	Generator	1,971 hp	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	800,000 gal/yr	0.08 tpy
421a	Generator	1,971 hp	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal		
500	Turbine	11,862 kW	Fuel Gas	250 ppmv	Mass Balance	42.1 lb/MMscf	8,760 hr/hr	22.2 tpy
501	Turbine	11,862 kW	Fuel Gas	250 ppmv	Mass Balance	42.1 lb/MMscf	8,760 hr/hr	22.2 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	250 ppmv	Mass Balance	42.1 lb/MMscf	8,760 hr/hr	5.9 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	250 ppmv	Mass Balance	42.1 lb/MMscf	8,760 hr/hr	0.2 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	250 ppmv	Mass Balance	42.1 lb/MMscf	257.9 MMscf/yr	5.4 tpy
Drill Rig Equipment								
1	Rig Engines	Various	Diesel/Fuel Gas	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	950,000 gal/yr	0.1 tpy [3]
8	Rig Boilers and Heaters	Various	Diesel/Fuel Gas					
Significant Emission Units - Estimated Potential Emissions - SO_2								**56.2 tpy**
Insignificant Emission Units								
417	Diesel Tank	15,000 barrels	NA	NA	NA	NA	8,760 hr/yr	0 tpy
418	Methanol Tank	450 barrels	NA	NA	NA	NA	8,760 hr/yr	0 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	NA	AP-42, Table 2.1-12	2.5 lb/ton	8,760 hr/yr	0.4 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	NA	AP-42, Table 2.1-12	2.5 lb/ton	8,760 hr/yr	0.5 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	4,380 hr/yr	0.003 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	4,380 hr/yr	0.003 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	4,380 hr/yr	0.003 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	4,380 hr/yr	0.003 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	0.0015 wt. pct. S	Mass Balance	2.1E-04 lb/gal	4,380 hr/yr	0.02 tpy
Insignificant Emission Units - Estimated Potential Emissions - SO_2								**0.9 tpy**
Total Estimated Potential Emissions - SO_2								**57.1 tpy**

Notes:

[1] Diesel fuel shall not exceed a maximum sulfur of 15 ppmw, per Condition 14, AQ0417TVP03. Fuel gas and produced gas H_2S content shall not exceed 250 ppmv, per Condition 13, AQ0417TVP03.

[2] Mass balance:

For fuel gas, the SO_2 emission factor is calculated based on the natural gas sulfur content.

ppmv H_2S = scf H_2S per MMscf fuel gas

Molar ratio: 1 mol H_2S = 1 mol S = 1 mol SO_2

Sulfur content of Natural Gas = 0.75 ppmv H_2S = 0.75 scf H_2S/MMscf fuel

SO_2 Emission Factor, lb/MMscf = (scf H_2S/MMscf fuel) x (64 lb SO_2/1mol S) / (379.9 scf/mol at STP)

For diesel units, the SO_2 emission factor is calculated based on the sulfur content in diesel fuel

Molar mass ratio is 32 lb S/mol : 64 lb SO_2/mol; Stoichiometry: 1 mol S = 1 mol SO_2

SO_2 Emission Factor, lb/gal = (Molar mass ratio, 2 lb SO_2: 1 lb S) x (weight % S in fuel) x (density of fuel, lb/gal) / 100%

[3] Conversions and parameters.

Diesel density (AP-42, Appendix A)	7.05	lb/gal
Engine heat rate (AP-42, Section 3.3)	7,000	Btu/hp-hr
Diesel Heat Content (AP-42, Appendix A)	137,000	Btu/gal
Vendor turbine Heat Rate	10,710	Btu/kW-hr
Gas HHV 2022 Average	1,056	Btu/scf

[3] Calculations are performed for boilers and heaters. Nonroad emissions are not included when determining stationary source classification.

Table D3-8. Potential Emissions (After Controls/Limitations) - Greenhouse Gas Carbon Dioxide Equivalent (CO_2e)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Potential Annual Greenhouse Gas Emissions (tpy)				
ID	Description	Rating/Capacity		CO_2	CH_4	N_2O	GHG Mass	GHG CO_2e
Significant Emission Units								
420a	Generator	1,971 hp	Diesel	8,935	3.6E-01	7.2E-02	8,936	8,966
421a	Generator	1,971 hp	Diesel					
500	Turbine	11,862 kW	Fuel Gas	65,091	1.23	0.123	65,092	65,158
501	Turbine	11,862 kW	Fuel Gas	65,091	1.23	0.123	65,092	65,158
503	Production Heater	34 MMBtu/hr	Fuel Gas	17,420	0.33	0.033	17,420	17,438
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	687	0.01	0.001	687	687
507	Flare	258 MMscf/yr	Fuel Gas and Produced Gas	15,929	0.30	0.030	15,929	15,945
Drill Rig Equipment								
1	Rig Engines	Various	Diesel/Fuel Gas	10,611	4.30E-01	8.61E-02	10,611.1	10,647.0
8	Rig Boilers and Heaters	Various	Diesel/Fuel Gas					
Significant Emission Units - Estimated Potential Emissions - Greenhouse Gases							**183,767**	**183,999**
Insignificant Emission Units								
417	Diesel Tank	15,000 barrels	NA	0	0	0	0	0
418	Methanol Tank	450 barrels	NA	0	0	0	0	0
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	305	0.1	0.01	305	312
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	370	0.1	0.02	371	379
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	357	0.01	0.003	357	358
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	357	0.01	0.003	357	358
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	357	0.01	0.003	357	358
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	357	0.01	0.003	357	358
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	2143	0.1	0.02	2,143	2,150
Insignificant Emission Units - Estimated Potential Emissions - Greenhouse Gases							**4,247**	**4,274**
Total Estimated Potential Emissions - Greenhouse Gases							**188,014**	**188,273**

Table D3-9. Potential Emissions (After Controls/Limitations) - Carbon Dioxide (CO_2)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel	Factor	Emission	Potential Annual	Potential Annual
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions [1]
Significant Emission Units							
420a	Generator	1,971 hp	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	800,000 gal/yr	8,935 tpy
421a	Generator	1,971 hp	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu		
500	Turbine	11,862 kW	Fuel Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/hr	65,091 tpy
501	Turbine	11,862 kW	Fuel Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/hr	65,091 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/hr	17,420 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/hr	687 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	257.9 lb/MMscf	15,929 tpy
Drill Rig Equipment							
1	Rig Engines	Various	Diesel/Fuel Gas	40 CFR 98, Table C-1	73.96 kg/MMBtu	950,000 gal/yr	10,611 tpy [2]
8	Rig Boilers and Heaters	Various	Diesel/Fuel Gas				
Significant Emission Units - Estimated Potential Emissions - CO_2							**183,763 tpy**
Insignificant Emission Units							
417	Diesel Tank	15,000 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
418	Methanol Tank	450 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	40 CFR 98, Table C-1	90.7 kg/MMBtu	8,760 hr/yr	305 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	40 CFR 98, Table C-1	90.7 kg/MMBtu	8,760 hr/yr	370 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	4,380 hr/yr	357 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	4,380 hr/yr	357 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	4,380 hr/yr	357 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	4,380 hr/yr	357 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	4,380 hr/yr	2,143 tpy
Insignificant Emission Units - Estimated Potential Emissions - CO_2							**4,246 tpy**
Total Estimated Potential Emissions- CO_2							**188,009 tpy**

Notes:

[1] Conversions and parameters.

Diesel Heat Content (AP-42, Appendix A)	137,000	Btu/gal
Engine heat rate (AP-42, Section 3.3)	7,000	Btu/hp-hr
Vendor turbine Heat Rate	10,710	Btu/kW-hr
Gas HHV 2022 Average	1,056	Btu/scf
Solid waste heat value (40 CFR 98, Table C-1)	9.95	MMBtu/ton

[2] Calculations are performed for boilers and heaters.

Table D3-10. Potential Emissions (After Controls/Limitations) - Methane (CH_4)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel Type	Factor Reference	Emission Factor	Potential Annual Operation	Potential Annual Emissions [1]
ID	Description	Rating/Capacity					
Significant Emission Units							
420a	Generator	1,971 hp	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	800,000 gal/yr	0.4 tpy
421a	Generator	1,971 hp	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu		
500	Turbine	11,862 kW	Fuel Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hr/hr	1.2 tpy
501	Turbine	11,862 kW	Fuel Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hr/hr	1.2 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hr/hr	0.3 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hr/hr	0.01 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	257.9 lb/MMscf	0.3 tpy
Drill Rig Equipment							
1	Rig Engines	Various	Diesel/Fuel Gas	45 CFR 98, Table C-2	0.003 kg/MMBtu	950,000 gal/yr	0.4 tpy [2]
8	Rig Boilers and Heaters	Various	Diesel/Fuel Gas				
Significant Emission Units - Estimated Potential Emissions - CH_4							**3.9 tpy**
Insignificant Emission Units							
417	Diesel Tank	15,000 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
418	Methanol Tank	450 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	40 CFR 98, Table C-2	0.032 kg/MMBtu	8,760 hr/yr	0.1 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	40 CFR 98, Table C-2	0.032 kg/MMBtu	8,760 hr/yr	0.1 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	4,380 hr/yr	0.01 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	4,380 hr/yr	0.01 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	4,380 hr/yr	0.01 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	4,380 hr/yr	0.01 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	4,380 hr/yr	0.1 tpy
Insignificant Emission Units - Estimated Potential Emissions - CH_4							**0.4 tpy**
Total Estimated Potential Emissions - CH_4							**4.3 tpy**

Notes:

[1] Conversions and parameters.

Diesel Heat Content (AP-42, Appendix A)	137,000 Btu/gal
Engine heat rate (AP-42, Section 3.3)	7,000 Btu/hp-hr
Vendor turbine Heat Rate	10,710 Btu/kW-hr
Gas HHV 2022 Average	1,056 Btu/scf
Solid waste heat value (40 CFR 98, Table C-1)	9.95 MMBtu/ton

[2] Calculations are performed for boilers and heaters.

Table D3-11. Potential Emissions (After Controls/Limitations) - Nitrous Oxide (N_2O)
Savant Alaska, LLC - Badami Development Facility

Emission Unit			Fuel	Factor	Emission	Potential Annual	Potential Annual
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions [1]
Significant Emission Units							
420a	Generator	1,971 hp	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	800,000 gal/yr	0.1 tpy
421a	Generator	1,971 hp	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu		
500	Turbine	11,862 kW	Fuel Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hr/hr	0.1 tpy
501	Turbine	11,862 kW	Fuel Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hr/hr	0.1 tpy
503	Production Heater	34 MMBtu/hr	Fuel Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hr/hr	0.03 tpy
505	TEG Reboiler	1.34 MMBtu/hr	Fuel Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hr/hr	0.001 tpy
507	Flare	257.9 MMscf/yr	Fuel Gas and Produced Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	257.9 lb/MMscf	0.03 tpy
Drill Rig Equipment							
1	Rig Engines	Various	Diesel/Fuel Gas	40 CFR 98, Table C-2	0.0006 kg/MMBtu	950,000 gal/yr	0.09 tpy [2]
8	Rig Boilers and Heaters	Various	Diesel/Fuel Gas				
Significant Emission Units - Estimated Potential Emissions - N_2O							**0.5 tpy**
Insignificant Emission Units							
417	Diesel Tank	15,000 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
418	Methanol Tank	450 barrels	NA	NA	NA	8,760 hr/yr	0 tpy
422	Smart Ash 100-A Incinerator	0.035 tons/hr	Oily Waste	40 CFR 98, Table C-2	0.0042 kg/MMBtu	8,760 hr/yr	0.01 tpy
502	Therm-Tec-G-12 Incinerator	85.0 lb/hr	Waste	40 CFR 98, Table C-2	0.0042 kg/MMBtu	8,760 hr/yr	0.02 tpy
607	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	4,380 hr/yr	0.003 tpy
608	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	4,380 hr/yr	0.003 tpy
611	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	4,380 hr/yr	0.003 tpy
612	Indirect Fire Heater	1.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	4,380 hr/yr	0.003 tpy
NA	Hot Oil Heater	6.0 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	4,380 hr/yr	0.02 tpy
Insignificant Emission Units - Estimated Potential Emissions - N_2O							**0.06 tpy**
Total Estimated Potential Emissions - N_2O							**0.5 tpy**

Notes:

[1] Conversions and parameters.

Diesel Heat Content (AP-42, Appendix A)	137,000	Btu/gal
Engine heat rate (AP-42, Section 3.3)	7,000	Btu/hp-hr
Vendor turbine Heat Rate	10,710	Btu/kW-hr
Gas HHV 2022 Average	1,056	Btu/scf
Solid waste heat value (40 CFR 98, Table C-1)	9.95	MMBtu/ton

[2] Calculations are performed for boilers and heaters.

Table D3-12. Potential Emissions (After Controls/Limitations) - Hazardous Air Pollutants (HAP)
Savant Alaska, LLC - Badami Development Facility

Hazardous Air Pollutant	Regulated Air Pollutant Emissions (tons per year)							
	Diesel Engines >600 hp	Natural Gas Turbines	Natural Gas Boilers/Heaters	Flares	Diesel Boilers/Heaters	Insignificant Incinerators	Insignificant Diesel Heaters	Total HAP Emissions[1]
Acetaldehyde	1.38E-03	4.45E-02	----	5.54E-03	----	----	----	**5.14E-02**
Acrolein	4.32E-04	7.12E-03	----	1.29E-03	----	----	----	**8.84E-03**
Benzene	4.25E-02	1.34E-02	3.08E-04	2.05E-02	1.02E-04	----	3.42E-05	**7.68E-02**
1,3-Butadiene	----	4.79E-04	----	----	----	----	----	**4.79E-04**
1,4-Dichlorobenzene(p)	----	----	1.76E-04	----	----	----	----	**1.76E-04**
Ethyl benzene	----	3.56E-02	----	1.86E-01	3.02E-05	----	1.02E-05	**2.22E-01**
Formaldehyde	4.3E-03	7.9E-01	1.1E-02	1.5E-01	0	----	5.3E-03	**9.77E-01**
N-Hexane	----	----	2.6E-01	1.3E+00	----	----	----	**1.60E+00**
Hydrochloric acid	----	----	----	----	----	7.30E-01	----	**7.30E-01**
Polycyclic Organic Matter (POM)	1.16E-02	2.45E-03	1.05E-04	1.81E-03	1.57E-03	----	5.28E-04	**1.80E-02**
Acenaphthene	2.56E-04	----	2.64E-06	----	1.20E-07	----	4.04E-08	**2.59E-04**
Acenaphthylene	5.06E-04	----	2.64E-07	----	1.00E-05	----	3.37E-06	**5.19E-04**
Anthracene	6.74E-05	----	3.52E-07	----	5.80E-07	----	1.95E-07	**6.85E-05**
Benzo(a)anthracene	3.41E-05	----	2.64E-07	----	1.90E-06	----	6.41E-07	**3.69E-05**
Benzo(a)pyrene	----	----	1.76E-07	----	----	----	----	**1.76E-07**
Benzo(b)fluoranthene	6.08E-05	----	2.64E-07	----	----	----	----	**6.11E-05**
Benzo(g,h,i)perylene	----	----	1.76E-07	----	----	----	----	**1.76E-07**
Benzo(g,h,l)perylene	----	----	----	----	1.07E-06	----	3.61E-07	**1.43E-06**
Benzo(k)fluoranthene	----	----	2.64E-07	----	----	----	----	**2.64E-07**
Chrysene	----	----	2.64E-07	----	1.13E-06	----	3.80E-07	**1.77E-06**
Dibenz(a,h)anthracene	----	----	1.76E-07	----	7.93E-07	----	2.67E-07	**1.24E-06**
Fluorene	----	----	4.10E-07	----	2.12E-06	----	7.15E-07	**3.25E-06**
Fluoranthene	----	----	4.40E-07	----	2.30E-06	----	7.74E-07	**3.51E-06**
Indeno(1,2,3-cd)pyrene	----	----	----	----	1.02E-06	----	3.42E-07	**1.36E-06**
2-Methylnaphthalene	----	----	3.52E-06	----	----	----	----	**3.52E-06**
Naphthalene	----	1.45E-03	8.94E-05	1.42E-03	5.37E-04	----	1.81E-04	**3.67E-03**
Phenanthrene	----	----	2.49E-06	----	4.99E-06	----	1.68E-06	**9.16E-06**
Pyrene	----	----	7.33E-07	----	2.02E-06	----	6.79E-07	**3.43E-06**
Propylene oxide	----	3.23E-02	----	----	----	----	----	**3.23E-02**
Toluene	1.54E-02	1.45E-01	4.98E-04	7.48E-03	2.95E-03	----	9.91E-04	**1.72E-01**
1,1,1-Trichloroethane	----	----	----	----	1.12E-04	----	3.77E-05	**1.50E-04**
Xylenes	1.06E-02	7.12E-02	----	3.74E-03	5.18E-05	----	1.74E-05	**8.56E-02**

Table D3-12. Potential Emissions (After Controls/Limitations) - Hazardous Air Pollutants (HAP)
Savant Alaska, LLC - Badami Development Facility

Hazardous Air Pollutant	Regulated Air Pollutant Emissions (tons per year)							
	Diesel Engines >600 hp	Natural Gas Turbines	Natural Gas Boilers/Heaters	Flares	Diesel Boilers/Heaters	Insignificant Incinerators	Insignificant Diesel Heaters	Total HAP Emissions[1]
Arsenic Compounds	----	----	----	----	2.60E-04	2.27E-04	8.76E-05	**5.75E-04**
Beryllium Compounds	----	----	----	----	1.95E-04	----	6.57E-05	**2.61E-04**
Cadmium Compounds	----	----	----	----	1.95E-04	8.18E-04	6.57E-05	**1.08E-03**
Chromium Compounds	----	----	----	----	1.95E-04	1.12E-03	6.57E-05	**1.38E-03**
Lead Compounds	----	----	7.74E-02	----	5.86E-04	----	1.97E-04	**7.82E-02**
Manganese Compounds	----	----	----	----	3.90E-04	----	1.31E-04	**5.22E-04**
Mercury Compounds	----	----	----	----	1.95E-04	1.90E-03	6.57E-05	**2.16E-03**
Nickel Compounds	----	----	----	----	1.95E-04	1.87E-03	6.57E-05	**2.13E-03**
Selenium Compounds	----	----	----	----	9.76E-04	----	3.29E-04	**1.30E-03**
Dioxins/Furans	----	----	----	----	----	9.98E-07	----	**9.98E-07**
Total HAPs - Maximum Individual HAP	**4.3E-02**	**0.8**	**0.3**	**1.3**	**0**	**0.7**	**0.01**	**1.6**
Total VOC HAP Emissions	**8.6E-02**	**1.1**	**0.3**	**1.7**	**0**	**0**	**0.01**	**3.2**
Total HAPs Emissions	**8.6E-02**	**1.1**	**0.4**	**1.7**	**0**	**0.7**	**0.01**	**4.1**

Notes:
[1] See individual emissions unit category emissions calculations for details on methodology and assumptions in the electronic copy.

Table D3-13. Potential Emissions (After Controls/Limitations) - Hazardous Air Pollutants (HAP)
Diesel Engines Greater Than or Equal to 600 Horsepower

Maximum Total Heat Input: 109,600.0 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**Emission Factor [2]**	**Estimated Emissions**
75-07-0	Acetaldehyde	2.52E-05 lb/MMBtu	1.38E-03 tpy
107-02-8	Acrolein	7.88E-06 lb/MMBtu	4.32E-04 tpy
71-43-2	Benzene	7.76E-04 lb/MMBtu	4.25E-02 tpy
50-00-0	Formaldehyde	7.89E-05 lb/MMBtu	4.32E-03 tpy
108-88-3	Toluene	2.81E-04 lb/MMBtu	1.54E-02 tpy
1330-20-7	Xylenes	1.93E-04 lb/MMBtu	1.06E-02 tpy
N/A	Polycyclic Organic Matter (POM)	2.12E-04 lb/MMBtu	1.16E-02 tpy
	Polycyclic aromatic compounds(PAH)		
208-96-8	Acenaphthene	4.68E-06 lb/MMBtu	2.56E-04 tpy
83-32-9	Acenaphthylene	9.23E-06 lb/MMBtu	5.06E-04 tpy
120-12-7	Anthracene	1.23E-06 lb/MMBtu	6.74E-05 tpy
56-55-3	Benzo(a)anthracene	6.22E-07 lb/MMBtu	3.41E-05 tpy
205-99-2	Benzo(b)fluoranthene	1.11E-06 lb/MMBtu	6.08E-05 tpy
207-08-9	Benzo(k)fluoranthene	2.18E-07 lb/MMBtu	1.19E-05 tpy
50-32-8	Benzo(a)pyrene	2.57E-07 lb/MMBtu	1.41E-05 tpy
191-24-2	Benzo(g,h,l)perylene	5.56E-07 lb/MMBtu	3.05E-05 tpy
218-01-9	Chrysene	1.53E-06 lb/MMBtu	8.38E-05 tpy
53-70-3	Dibenz(a,h)anthracene	3.46E-07 lb/MMBtu	1.90E-05 tpy
206-44-0	Fluoranthene	4.03E-06 lb/MMBtu	2.21E-04 tpy
86-73-7	Fluorene	1.28E-05 lb/MMBtu	7.01E-04 tpy
193-39-5	Indeno(1,2,3-cd)pyrene	4.14E-07 lb/MMBtu	2.27E-05 tpy
91-20-3	Naphthalene	1.30E-04 lb/MMBtu	7.12E-03 tpy
85-01-8	Phenanthrene	4.08E-05 lb/MMBtu	2.24E-03 tpy
129-00-0	Pyrene	3.71E-06 lb/MMBtu	2.03E-04 tpy

Total Potential HAP Emissions: 8.62E-02 tpy

[1] Total fuel use based on maximum full-time operation as noted below:

EU ID 420a	Generator	1,971 hp	800,000 gal/yr, comb.
EU ID 420b	Generator	1,971 hp	

Potential Heat Input: 109,600 MMBtu/yr

Total Potential Heat Input: 109,600 MMBtu/yr

Diesel Heat Content (AP-42, Appendix A) 137,000 Btu/gal

[2] Reference: AP-42, Tables 3.4-3 and 3.4-4.

Table D3-14. Potential Emissions (After Controls/Limitations) - Hazardous Air Pollutants (HAP)
Natural Gas Fired Turbines

Maximum Total Heat Input: 2,225,776 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**Emission Factor [2]**	**Estimated Emissions**
106-99-0	1,3-Butadiene	4.30E-07 lb/MMBtu	4.79E-04 tpy
75-07-0	Acetaldehyde	4.00E-05 lb/MMBtu	4.45E-02 tpy
107-02-8	Acrolein	6.40E-06 lb/MMBtu	7.12E-03 tpy
71-43-2	Benzene	1.20E-05 lb/MMBtu	1.34E-02 tpy
100-41-4	Ethyl benzene	3.20E-05 lb/MMBtu	3.56E-02 tpy
50-00-0	Formaldehyde	7.10E-04 lb/MMBtu	7.90E-01 tpy
91-20-3	Naphthalene	1.30E-06 lb/MMBtu	1.45E-03 tpy
	Polycyclic Organic Matter (POM)	2.20E-06 lb/MMBtu	2.45E-03 tpy
	Polycyclic aromatic compounds(PAH)	2.20E-06 lb/MMBtu	
75-56-9	Propylene oxide	2.90E-05 lb/MMBtu	3.23E-02 tpy
108-88-3	Toluene	1.30E-04 lb/MMBtu	1.45E-01 tpy
1330-20-7	Xylenes	6.40E-05 lb/MMBtu	7.12E-02 tpy

Total Potential HAP Emissions: 1.14 tpy

Notes:

[1] Total fuel use based on maximum full-time operation as noted below:

EU ID 500	Turbine	11,862 kW	8,760	hr/yr
EU ID 501	Turbine	11,862 kW	8,760	hr/yr

Potential Heat Input: 2,225,776 MMBtu/yr, operating

Total Potential Heat Input: 2,225,776 MMBtu/yr

Vendor Turbine Heat Rate: 10,710 Btu/kW-hr

[2] Reference: AP-42, Tables 3.1-3.

Table D3-15. Potential Emissions (After Controls/Limitations) - Hazardous Air Pollutants (HAP)
Natural Gas Fired Heaters

Maximum Total Heat Input: 309,578 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**Emission Factor [2,3]**	**Estimated Emissions**
106-46-7	1,4-Dichlorobenzene(p)	1.20E-03 lb/MMscf	1.76E-04 tpy
71-43-2	Benzene	2.10E-03 lb/MMscf	3.08E-04 tpy
50-00-0	Formaldehyde	7.52E-02 lb/MMscf	1.10E-02 tpy
	Lead Compounds	5.00E-04 lb/MMscf	7.74E-02 tpy
110-54-3	N-Hexane	1.8 lb/MMscf	2.64E-01 tpy
	Polycyclic Organic Matter (POM)	7.14E-04 lb/MMscf	1.05E-04 tpy
	Polycyclic aromatic compounds(PAH)		
91-57-6	2-Methylnaphthalene	2.40E-05 lb/MMscf	3.52E-06 tpy
83-32-9	Acenaphthene	1.80E-05 lb/MMscf	2.64E-06 tpy
203-96-8	Acenaphthylene	1.80E-06 lb/MMscf	2.64E-07 tpy
120-12-7	Anthracene	2.40E-06 lb/MMscf	3.52E-07 tpy
56-55-3	Benzo(a)anthracene	1.80E-06 lb/MMscf	2.64E-07 tpy
205-99-2	Benzo(b)fluoranthene	1.80E-06 lb/MMscf	2.64E-07 tpy
207-08-9	Benzo(k)fluoranthene	1.80E-06 lb/MMscf	2.64E-07 tpy
50-32-8	Benzo(a)pyrene	1.20E-06 lb/MMscf	1.76E-07 tpy
191-24-2	Benzo(g,h,i)perylene	1.20E-06 lb/MMscf	1.76E-07 tpy
218-01-9	Chrysene	1.80E-06 lb/MMscf	2.64E-07 tpy
53-70-3	Dibenz(a,h)anthracene	1.20E-06 lb/MMscf	1.76E-07 tpy
	7,12-dimethylbenzanthracene	1.60E-05 lb/MMscf	2.35E-06 tpy
206-44-0	Fluoranthene	3.00E-06 lb/MMscf	4.40E-07 tpy
86-73-7	Fluorene	2.80E-06 lb/MMscf	4.10E-07 tpy
193-39-5	Ideno(1,2,3-cd)pyrene	1.80E-06 lb/MMscf	2.64E-07 tpy
56-49-5	3-methylcholanthrene	1.80E-06 lb/MMscf	2.64E-07 tpy
91-20-3	Naphthalene	6.10E-04 lb/MMscf	8.94E-05 tpy
85-01-8	Phenanthrene	1.70E-05 lb/MMscf	2.49E-06 tpy
129-00-0	Pyrene	5.00E-06 lb/MMscf	7.33E-07 tpy
108-88-3	Toluene	3.40E-03 lb/MMscf	4.98E-04 tpy

Total Potential HAP Emissions: 0.35 tpy

[1] Total fuel use based on maximum full-time operationas noted below:

EU ID 503	Production Heater	34.0 MMBtu/hr			
	Potential Heat Input:		297,840	MMBtu/yr, operating	8,760 hr/yr
EU ID 505	TEG Reboiler	1.34 MMBtu/hr			
	Potential Heat Input:		11,738	MMBtu/yr, operating	8,760 hr/yr
	Total Potential Heat Input:		**309,578**	**MMBtu/yr**	

[2] Reference: AP-42, Tables 1.4-2 and 1.4-3.

[3] Average gross heating value from CY2022: 1,056 Btu/scf

Table D3-16. Potential Emissions (After Controls/Limitations) - Hazardous Air Pollutants (HAP)
Diesel Fired Heaters

Maximum Total Heat Input: 130,150 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations		
CAS No.	**Chemical Name**	**Emission Factor [2,3]**		**Estimated Emissions**
	Arsenic Compounds	4.00E-06	lb/MMBtu	2.60E-04 tpy
71-43-2	Benzene	1.56E-06	lb/MMBtu	1.02E-04 tpy
	Beryllium Compounds	3.00E-06	lb/MMBtu	1.95E-04 tpy
	Cadmium Compounds	3.00E-06	lb/MMBtu	1.95E-04 tpy
	Chromium Compounds	3.00E-06	lb/MMBtu	1.95E-04 tpy
100-41-4	Ethyl benzene	4.64E-07	lb/MMBtu	3.02E-05 tpy
50-00-0	Formaldehyde	2.41E-04	lb/MMBtu	1.57E-02 tpy
	Lead Compounds	9.00E-06	lb/MMBtu	5.86E-04 tpy
	Manganese Compounds	6.00E-06	lb/MMBtu	3.90E-04 tpy
	Mercury Compounds	3.00E-06	lb/MMBtu	1.95E-04 tpy
	Nickel Compounds	3.00E-06	lb/MMBtu	1.95E-04 tpy
	Polycyclic Organic Matter (POM)	2.41E-05	lb/MMBtu	1.57E-03 tpy
	Polycyclic aromatic compounds(PAH)			
83-32-9	Acenaphthylene	1.54E-07	lb/MMBtu	1.00E-05 tpy
208-96-8	Acenaphthene	1.85E-09	lb/MMBtu	1.20E-07 tpy
120-12-7	Anthracene	8.91E-09	lb/MMBtu	5.80E-07 tpy
56-55-3	Benzo(a)anthracene	2.93E-08	lb/MMBtu	1.90E-06 tpy
205-99-2/207-08-9	Benzo(b,k)fluoranthene	1.08E-08	lb/MMBtu	7.03E-07 tpy
191-24-2	Benzo(g,h,l)perylene	1.65E-08	lb/MMBtu	1.07E-06 tpy
218-01-9	Chrysene	1.74E-08	lb/MMBtu	1.13E-06 tpy
53-70-3	Dibenz(a,h)anthracene	1.22E-08	lb/MMBtu	7.93E-07 tpy
206-44-0	Fluoranthene	3.53E-08	lb/MMBtu	2.30E-06 tpy
86-73-7	Fluorene	3.26E-08	lb/MMBtu	2.12E-06 tpy
193-39-5	Indeno(1,2,3-cd)pyrene	1.56E-08	lb/MMBtu	1.02E-06 tpy
91-20-3	Naphthalene	8.25E-06	lb/MMBtu	5.37E-04 tpy
85-01-8	Phenanthrene	7.66E-08	lb/MMBtu	4.99E-06 tpy
129-00-0	Pyrene	3.10E-08	lb/MMBtu	2.02E-06 tpy
	Selenium Compounds	1.50E-05	lb/MMBtu	9.76E-04 tpy
108-88-3	Toluene	4.53E-05	lb/MMBtu	2.95E-03 tpy
71-55-6	1,1,1-Trichloroethane	1.72E-06	lb/MMBtu	1.12E-04 tpy
1330-20-7	Xylenes	7.96E-07	lb/MMBtu	5.18E-05 tpy

Total Potential HAP Emissions: 2.37E-02 tpy

[1] Total fuel use based on maximum full-time operation as noted below:

EU ID I	Rig Boilers and Heaters	950,000	gallons	
	Potential Heat Input:		130,150	MMBtu/yr
	Total Potential Heat Input:		**130,150**	**MMBtu/yr**

[2] Reference: AP-42, Tables 1.3-8, 1.3-9, and 1.3-10.

[3] Diesel Fuel Heat Content (AP-42, Appendix A): 137,000 Btu/gal

Table D3-17. Potential Emissions (After Controls/Limitations) - Hazardous Air Pollutants (HAP)
Flares

Maximum Total Heat Input: 257.9 MMscf/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations			
CAS No.	**Chemical Name**	**Emission Factor [2,3]**		**Estimated Emissions**	
	Flared Gas:				
75-07-0	Acetaldehyde	0.043	lb/MMscf	5.54E-03	tpy
107-02-8	Acrolein	0.010	lb/MMscf	1.29E-03	tpy
71-43-2	Benzene	0.159	lb/MMscf	2.05E-02	tpy
100-41-4	Ethyl benzene	1.444	lb/MMscf	1.86E-01	tpy
50-00-0	Formaldehyde	1.169	lb/MMscf	1.51E-01	tpy
110-54-3	N-Hexane	0.029	lb/MMscf	3.74E-03	tpy
91-20-3	Naphthalene	0.011	lb/MMscf	1.42E-03	tpy
108-88-3	Toluene	0.058	lb/MMscf	7.48E-03	tpy
1330-20-7	Xylenes	0.029	lb/MMscf	3.74E-03	tpy
	Polycyclic Organic Matter (POM)	0.014	lb/MMscf	1.81E-03	tpy
	Uncombusted Gas:				
110-54-3	N-Hexane	10.297	lb/MMscf	1.3E+00	tpy

Total Potential HAP Emissions: 1.71 tpy

[1] Total fuel use based on maximum full-time operation as noted below:

EU ID 507 Flare

Potential Consumption: 257.9 MMscf/yr

Total Potential Heat Input: 257.9 MMscf/yr

[2] Reference: VCAPCD AB 2588 (Flares - Natural Gas)

[3] Flare destruction efficiency estimated at 98%.

[3] October 9, 2017 gas analysis, 0.227 mole percent hexane plus (0.20 lbs/lb-mol).

Table D3-18. Potential Emissions (After Controls/Limitations) - Hazardous Air Pollutants (HAP)
Insignificant Incinerators

Maximum Total Heat Input: 679 ton/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**Emission Factor [2]**	**Estimated Emissions**
	Arsenic Compounds	6.69E-04 lb/ton	0.000227092 tpy
	Cadmium Compounds	2.41E-03 lb/ton	8.18E-04 tpy
	Chromium Compounds	3.31E-03 lb/ton	1.12E-03 tpy
7647-01-0	Hydrochloric Acid	2.15E+00 lb/ton	0.73 tpy
	Mercury Compounds	5.60E-03 lb/ton	1.90E-03 tpy
	Nickel Compounds	5.52E-03 lb/ton	1.87E-03 tpy
	Dioxins/Furans	2.94E-06 lb/ton	9.98E-07 tpy

Total Potential HAP Emissions: 0.7 tpy

Notes:

[1] Total incinerated weight based on maximum operation for the following:

422	Smart Ash 100-A Incinerator	0.04 tons/hr			
	Potential Heat Input:		307 tons/yr, operating	8,760	hr/yr
502	Therm-Tec-G-12 Incinerator	85 lb/hr			
	Potential Heat Input:		372 tons/yr, operating	8,760	hr/yr

Total Potential Waste incinerated: 679 ton/yr

[2] Reference: AP-42, Tables 2.1-9, Modular Starved-Air Combustors.

Table D3-19. Potential Emissions (After Controls/Limitations) - Hazardous Air Pollutants (HAP)
Insignificant Diesel Fired Heaters

Maximum Total Heat Input: 43,800 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**Emission Factor [2,3]**	**Estimated Emissions**
	Arsenic Compounds	4.00E-06 lb/MMBtu	8.76E-05 tpy
71-43-2	Benzene	1.56E-06 lb/MMBtu	3.42E-05 tpy
	Beryllium Compounds	3.00E-06 lb/MMBtu	6.57E-05 tpy
	Cadmium Compounds	3.00E-06 lb/MMBtu	6.57E-05 tpy
	Chromium Compounds	3.00E-06 lb/MMBtu	6.57E-05 tpy
100-41-4	Ethyl benzene	4.64E-07 lb/MMBtu	1.02E-05 tpy
50-00-0	Formaldehyde	2.41E-04 lb/MMBtu	5.28E-03 tpy
	Lead Compounds	9.00E-06 lb/MMBtu	1.97E-04 tpy
	Manganese Compounds	6.00E-06 lb/MMBtu	1.31E-04 tpy
	Mercury Compounds	3.00E-06 lb/MMBtu	6.57E-05 tpy
	Nickel Compounds	3.00E-06 lb/MMBtu	6.57E-05 tpy
	Polycyclic Organic Matter (POM)	2.41E-05 lb/MMBtu	5.28E-04 tpy
	Polycyclic aromatic compounds(PAH)		
83-32-9	Acenaphthylene	1.54E-07 lb/MMBtu	3.37E-06 tpy
208-96-8	Acenaphthene	1.85E-09 lb/MMBtu	4.04E-08 tpy
120-12-7	Anthracene	8.91E-09 lb/MMBtu	1.95E-07 tpy
56-55-3	Benzo(a)anthracene	2.93E-08 lb/MMBtu	6.41E-07 tpy
205-99-2/207-08-9	Benzo(b,k)fluoranthene	1.08E-08 lb/MMBtu	2.37E-07 tpy
191-24-2	Benzo(g,h,l)perylene	1.65E-08 lb/MMBtu	3.61E-07 tpy
218-01-9	Chrysene	1.74E-08 lb/MMBtu	3.80E-07 tpy
53-70-3	Dibenz(a,h)anthracene	1.22E-08 lb/MMBtu	2.67E-07 tpy
206-44-0	Fluoranthene	3.53E-08 lb/MMBtu	7.74E-07 tpy
86-73-7	Fluorene	3.26E-08 lb/MMBtu	7.15E-07 tpy
193-39-5	Indeno(1,2,3-cd)pyrene	1.56E-08 lb/MMBtu	3.42E-07 tpy
91-20-3	Naphthalene	8.25E-06 lb/MMBtu	1.81E-04 tpy
85-01-8	Phenanthrene	7.66E-08 lb/MMBtu	1.68E-06 tpy
129-00-0	Pyrene	3.10E-08 lb/MMBtu	6.79E-07 tpy
NA	Selenium Compounds	1.50E-05 lb/MMBtu	3.29E-04 tpy
108-88-3	Toluene	4.53E-05 lb/MMBtu	9.91E-04 tpy
71-55-6	1,1,1-Trichloroethane	1.72E-06 lb/MMBtu	3.77E-05 tpy
1330-20-7	Xylenes	7.96E-07 lb/MMBtu	1.74E-05 tpy

Total Potential HAP Emissions: 0.008 tpy

[1] Total fuel use based on maximum full-time operation as noted below:

EU 607	Indirect Fire Heater	1 MMBtu/hr			
	Potential Heat Input:		4,380	MMBtu/yr, operating	4,380 hr/yr
EU 608	Indirect Fire Heater	1 MMBtu/hr			
	Potential Heat Input:		4,380	MMBtu/yr, operating	4,380 hr/yr
EU 611	Indirect Fire Heater	1 MMBtu/hr			
	Potential Heat Input:		4,380	MMBtu/yr, operating	4,380 hr/yr
EU 612	Indirect Fire Heater	1 MMBtu/hr			
	Potential Heat Input:		4,380	MMBtu/yr, operating	4,380 hr/yr
NA	Hot Oil Heater	6 MMBtu/hr			
			26,280	MMBtu/yr, operating	4,380 hr/yr

Total Potential Heat Input: 43,800 MMBtu/yr

[2] Reference: AP-42, Tables 1.3.8, 1.3-9, and 1.3-10.

[3] Diesel Fuel Heat Content (AP-42, Appendix A): 137,000 Btu/gal

SECTION E
REGULATORY REQUIREMENTS

Form E1: Stationary Source-Wide Applicable Requirements

Form E4: Permit Shield Request

Form E5: Alternative Monitoring Plans

FORM E1

Stationary Source - Wide Applicable Requirements

Permit Number: AQ0417TVP02, Revision 2

Stationary Source-Wide Applicable Requirements (attach additional sheets as needed):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
AQ0417TVP02, Rev 2 – Condition 12	AQ0417MSS05 Condition 7.2	Limit to Protect Ambient Air Quality Standard	Establish and maintain the ambient boundaries used in the ambient impact analysis.	Yes	Comply with the May 10, 2005 "CPF Pad Badami Unit – Public Access Control Plan" or subsequent version approved by ADEC.
AQ0417TVP02, Rev 2 – Condition 17.3.a(i)	AQ0417MSS05 Condition 12.1.d(i)	Best Available Control Technology Limits	H2S content of fuel gas and produced fuel shall not exceed 250 ppmv.	Yes	Monitor, record, and report in accordance with Conditions 10.6 through 10.8, 18.3, and 18.5.
AQ0417TVP02, Rev 2 – Condition 17.3.a(ii)	AQ0417MSS05 Condition 12.1.d(ii)	Best Available Control Technology Limits	Sulfur content of fuel oil shall not exceed 0.15 wt% S.	Yes	Monitor, record, and report in accordance with Conditions 10.1 through 10.4, 18.3, and 18.5.
AQ0417TVP02, Rev 2 – Condition 17.4	AQ0417MSS05 Condition 12.1.e	Best Available Control Technology Limits	VOC BACT for fuel burning equipment and fuel storage tanks, and water treatment processes is no controls with good operation practices. BACT for water injection tanks and slop tank is a sealed system design. No emission limits are imposed as representing BACT.	Yes	Report in accordance with Condition 18.5 as applicable.
AQ0417TVP02, Rev 2 – Condition 17.5(iv)	AQ0417MSS05 Condition 12.1.f(iii)	Best Available Control Technology Limits	All other industrial processes (excluding EU IDs 420a, 421a, 500 and 501), incinerators, and fuel burning equipment shall comply with the applicable State visible emission standards listed in Conditions 1 and 22.1.	Yes	Report in accordance with Condition 18.5 as applicable.
AQ0417TVP02, Rev 2 – Condition 22.1	18 AAC 50.055(a)(1)	Visible Emissions	For insignificant emission units not listed in the permit do not cause or allow visible emissions to reduce visibility by more than 20 percent averaged over any six consecutive minutes.	Yes	Monitor, record, and report in accordance with Condition 22.4.

FORM E1

Stationary Source - Wide Applicable Requirements

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
AQ0417TVP02, Rev 2 – Condition 22.2	18 AAC 50.055(b)(1)	Particulate Matter (PM) Emissions	For insignificant emission units not listed in the permit do not cause or allow particulate matter to exceed 0.05 grains per cubic foot of exhaust gas averaged over three hours.	Yes	Monitor, record, and report in accordance with Condition 22.4.
AQ0417TVP02, Rev 2 – Condition 22.3	18 AAC 50.055(c)	Sulfur Compound Emissions	For insignificant emission units not listed in the permit do not cause or allow sulfur compound emissions to exceed 500 ppm averaged over three hours.	Yes	Monitor, record, and report in accordance with Condition 22.4.
AQ0417TVP02, Rev 2 – Condition 39	40 CFR 61 Subparts A &M and Appendix A	Asbestos NESHAP	Comply with the requirements set forth in 40 CFR 61.145 and 61.150 of Subpart M, and the applicable sections set forth in 40 CFR 61, Subpart A and Appendix A.	Yes	Reasonable Inquiry
AQ0417TVP02, Rev 2 – Condition 40.1	40 CFR 82 Subpart F	Protection of Stratospheric Ozone	Comply with the standards for recycling and emission reduction of refrigerants set forth in 40 CFR 82, Subpart F.	Yes	Reasonable Inquiry
AQ0417TVP02, Rev 2 – Condition 40.2	40 CFR 82.147(b)-(d)	Protection of Stratospheric Ozone	Comply with the applicable prohibitions set out in 40 CFR 82.174(b) – (d) (Protection of Stratospheric Ozone Subpart G – Significant New Alternatives Policy Program).	Yes	Reasonable Inquiry
AQ0417TVP02, Rev 2 – Condition 40.3	40 CFR 270(b)-(f)	Protection of Stratospheric Ozone	Comply with the applicable prohibitions set out in 40 CFR 82.270(b) – (f) (Protection of Stratospheric Ozone Subpart H – Halon Emission Reduction).	Yes	Reasonable Inquiry
AQ0417TVP02, Rev 2 – Condition 41	40 CFR 63.1(b) & 63.6(c)(1)	NESHAPs Applicability Determinations	Determine rule applicability and designation of affected sources under National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Source Categories (40 CFR 63) in accordance with the procedures described in 40 CFR 63.1(b). If a source becomes affected by an applicable subpart of 40 CFR 63, comply with such standard by the compliance date established by the Administrator in the applicable subpart, in accordance with 40 CFR 63.6(c).	Yes	Reasonable Inquiry / Record Review

FORM E1

Stationary Source - Wide Applicable Requirements

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
AQ0417TVP02, Rev 2 – Condition 42.1	40 CFR 60.13, 63.10(d) & (f), and 71.6(c)(6)	NSPS and NESHAP Reports	Attach to the operating report for the period covered by the report, a copy of any NSPS and NESHAPs reports submitted to the U.S. Environmental Protection Agency (EPA) Region 10.	Yes	Reasonable Inquiry / Record Review
AQ0417TVP02, Rev 2 – Condition 42.2	40 CFR 60.13, 63.10(d) & (f), and 71.6(c)(6)	NSPS and NESHAP Reports	Upon request, provide a written copy of any EPA granted alternative monitoring requirement, custom monitoring schedule or waiver of the Federal emission standards, recordkeeping, monitoring, performance testing, or reporting requirements. Keep a copy of each U.S. EPA issued monitoring waiver or custom monitoring schedule with the permit.	Yes	Reasonable Inquiry / Record Review
AQ0417TVP02, Rev 2 – Condition 43	18 AAC 50.345(a) & (e)	Standard terms and conditions	Each permit term and condition is independent and remains valid regardless of a challenge to any other part of the permit.	Not applicable	Not applicable
AQ0417TVP02, Rev 2 – Condition 44	18 AAC 50.345 (a) & (f)	Standard terms and conditions	Requested permit changes do not stay any permit condition.	Not applicable	Not applicable
AQ0417TVP02, Rev 2 – Condition 45	18 AAC 50.345 (a) & (g)	Standard terms and conditions	The permit does not convey any property rights of any sort, nor any exclusive privilege.	Not applicable	Not applicable
AQ0417TVP02, Rev 2 – Condition 46	18 AAC 50.400 - 405	Administration fees	The Permittee shall pay all assessed permit administration fees.	Yes	Record Review
AQ0417TVP02, Rev 2 – Condition 47	18 AAC 50.410	Emission fees	The Permittee shall pay the Department an annual emission fee based on the assessable emissions of the source.	Yes	Emission fees were paid based on calculated emission estimates.
AQ0417TVP02, Rev 2 – Condition 48	18 AAC 50.410	Assessable emission estimate	Calculate assessable emissions and submit them to the Department by March 31 or plan to pay fees based on the potential emissions.	Yes	Record Review
AQ0417TVP02, Rev 2 – Condition 50	18 AAC 50.045(a)	Dilution	The Permittee shall not dilute emissions.	Yes	Reasonable Inquiry
AQ0417TVP02, Rev 2 – Condition 51	18 AAC 50.045(d)	Fugitive dust	Take reasonable precautions to prevent fugitive dust.	Yes	Reasonable Inquiry/Record Review

FORM E1

Stationary Source - Wide Applicable Requirements

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
AQ0417TVP02, Rev 2 – Condition 52	18 AAC 50.055(g)	Stack injection	The Permittee shall not release materials other than process emissions, products of combustion or materials introduced to control pollutant emissions from a stack.	Yes	Reasonable Inquiry
AQ0417TVP02, Rev 2 – Condition 53	18 AAC 50.110	Air pollution prohibited	No person may permit any emission which is injurious to human health or welfare, animal or plant life, or property, or which interferes with the enjoyment of life or property.	Yes	Reasonable Inquiry/Record Review
AQ0417TVP02, Rev 2 – Condition 54	18 AAC 50.235	Technology-based emission standard	During an unavoidable emergency, malfunction, or non-routine repair, the Permittee shall take reasonable steps to minimize emissions.	Yes	Reasonable Inquiry/Record Review
AQ0417TVP02, Rev 2 – Condition 55	18 AAC 50.065	Open burning	The Permittee shall not conduct open burning.	Yes	Reasonable Inquiry
AQ0417TVP02, Rev 2 – Conditions 56 through 65	18 AAC 50.220	Source testing	General source testing and monitoring requirements.	Yes	Reasonable Inquiry/Record Review
AQ0417TVP02, Rev 2 – Condition 66	40 CFR 60.7(f)	Recordkeeping	Keep all applicable records for at least five years.	Yes	Record Review
AQ0417TVP02, Rev 2 – Condition 67	18 AAC 50.345(j)	Certification	Certify all reports, compliance certifications or other documents.	Yes	Record Review
AQ0417TVP02, Rev 2 – Condition 68	40 CFR 71.6(a)(3)(iii)(A)	Submittals	Submit two copies of reports, compliance certifications and other submittals require by the permit to the Department.	Yes	Record Review
AQ0417TVP02, Rev 2 – Condition 69	18 AAC 50.200	Information requests	Furnish to the Department any information requested in writing to determine compliance with the permit.	Yes	Reasonable Inquiry/Record Review
AQ0417TVP02, Rev 2 – Condition 70	18 AAC 50.235(a)(2)	Excess emissions and permit deviation reports	Report all emissions or operations that exceed or deviate from the permit.	Yes	Reasonable Inquiry/Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
AQ0417TVP02, Rev 2 – Condition 71	18 AAC 50.346 (a)	Operating reports	Compile and submit to the Department operating reports.	Yes	Record Review
AQ0417TVP02, Rev 2 – Condition 72	18 AAC 50.326(j)	Annual compliance certification	Compile and submit to the Department an annual compliance certification report.	Yes	Records Review
AQ0417TVP02, Rev 2 – Condition 73	40 CFR 51.15, 51.30(b)(1) and 40 CFR 51, Appendix A to Subpart A	Emission Inventory Reporting	The Permittee shall conduct Emission Inventory Reporting every three years.	Yes	Records Review
AQ0417TVP02, Rev 2 – Conditions 74	18 AAC 50.326(b) and (j)	Permit applications and submittals	The Permittee shall submit permit modifications and renewals to the Department and U.S. EPA.	Yes	Records Review
AQ0417TVP02, Rev 2 – Condition 75	18 AAC 50.326(j)	Emission trading	No permit revisions shall be required for changes that are provided for in the permit.	Not applicable	Not applicable
AQ0417TVP02, Rev 2 – Condition 76	18 AAC 50.326(j)	Off permit changes	The Permittee shall make changes that are not address or prohibited by this permit.	Yes	Reasonable Inquiry/Record Review
AQ0417TVP02, Rev 2 – Condition 77	18 AAC 50.326(j)	Operational flexibility	The Permittee may make changes if the changes are not modifications under Title I and do not exceed the allowable emissions.	Yes	Reasonable Inquiry/Record Review
AQ0417TVP02, Rev 2 – Condition 78	18 AAC 50.326(j)	Permit renewal	The Permittee shall submit an application between six and 18 months before the permit expires.	Yes	Reasonable Inquiry/Record Review
AQ0417TVP02, Rev 2 – Conditions 79 through 83	18 AAC 50.326(j)(3)	General compliance requirements	The Permittee shall comply with each permit term and condition and allow the Department access to the facility.	Yes	Reasonable Inquiry/Record Review
	40 CFR 60.5370a(a)	NSPS Subpart OOOOa General Requirements	The Permittee must be in compliance with the standards of this subpart no later than August 2, 2016, or upon startup, whichever is later.	Yes	Reasonable Inquiry/Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
	40 CFR 60.5370a(b)	NSPS Subpart OOOOa General Requirements	At all times, including periods of startup, shutdown, and malfunction, owners and operators shall maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.	Yes	Reasonable Inquiry/Record Review
	40 CFR 60.5375a	NSPS Subpart OOOOa Well Affected Facility	Comply with the requirements in 40 CFR 60.6375a(a) through (g) for each well completion operation with hydraulic fracturing on or after November 30, 2016.	Yes	Reasonable Inquiry/Record Review
	40 CFR 60.5375a(a)(1)	NSPS Subpart OOOOa Well Affected Facility Continued below	For each stage of the well completion operation follow the requirements in (1) through (3). (1) During the initial flowback stage, route the flowback into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the initial flowback stage is not subject to control. (2) During the separation flowback stage, route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the recovered liquids into the well or another well, or route the recovered liquids to a collection system. Route the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an onsite fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. If it is technically infeasible to route the recovered gas as required, follow the requirements in 40 CFR 60.5375a(a)(3). If, at any time during the separation flowback stage, it is technically infeasible for a separator to function, you must comply with (1).	Yes	Reasonable Inquiry/Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
	40 CFR 60.5375a(a)(1)	NSPS Subpart OOOOa Well Affected Facility Continued	(3) You must have a separator onsite during the entirety of the flowback period, except as provided below. (A) A well that is not hydraulically fractured or refractured with liquids, or that does not generate condensate, intermediate hydrocarbon liquids, or produced water such that there is no liquid collection system at the well site is not required to have a separator onsite. (B) If conditions allow for liquid collection, then the operator must immediately stop the well completion operation, install a separator, and restart the well completion operation. (C) If a well meets the criteria of (3)(A) or (B) the report in 40 CFR 60.5420a(b)(2) must be submitted and the records in 40 CFR 60.5420a(c)(1)(iii) must be maintained.	Yes	Reasonable Inquiry/Record Review
	40 CFR 60.5375a(a)(3)	NSPS Subpart OOOOa Well Affected Facility	If it is technically infeasible to route the recovered gas as required in 40 CFR 60.5375a(a)(1)(ii), then capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.	Yes	Reasonable Inquiry/Record Review
	40 CFR 60.5375a(a)(4)	NSPS Subpart OOOOa Well Affected Facility	The Permittee has a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.	Yes	Reasonable Inquiry/Record Review
	40 CFR 60.5375a(b)	NSPS Subpart OOOOa Well Affected Facility	Maintain a log for each well completion operation at each well affected facility. The log must be completed on a daily basis for the duration of the well completion operation and must contain the records specified in 40 CFR 60.5420a(c)(1)(iii).	Yes	Reasonable Inquiry/Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
	40 CFR 60.5375a(c)	NSPS Subpart OOOOa Well Affected Facility	Demonstrate initial compliance with the standards that apply to well affected facilities as required by 40 CFR 60.5410a(a).	Yes	Reasonable Inquiry/Record Review
	40 CFR 60.5375a(d)	NSPS Subpart OOOOa Well Affected Facility	Demonstrate continuous compliance with the standards that apply to well affected facilities as required by 40 CFR 60.5415a(a).	Yes	Reasonable Inquiry/Record Review
	40 CFR 60.5375a(e)	NSPS Subpart OOOOa Well Affected Facility	Perform the required notification, recordkeeping and reporting as required by 40 CFR 60.5420a(a)(2), (b)(1) and (2), and (c)(1).	Yes	Reasonable Inquiry/Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
	40 CFR 60.5375a(f)	NSPS Subpart OOOOa Well Affected Facility (Continued below)	For each well affected facility specified in (1) and (2), you must comply with the requirements of (3) and (4). (1) Each well completion operation with hydraulic fracturing at a wildcat or delineation well. (2) Each well completion operation with hydraulic fracturing at a non- wildcat low pressure well or non-delineation low pressure well. (3) You must comply with either (3)(i) or (ii), unless you meet the requirements in 40 CFR 60.5375a(g). You must also comply with 40 CFR 60.5375a(b). (3)(i) Route all flowback to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame. (3)(ii) Route all flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the flowback before the separator can function is not subject to control under this section. Capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.	Yes	Reasonable Inquiry/Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
	40 CFR 60.5375a(f)	NSPS Subpart OOOOa Well Affected Facility (Continued)	(4) Submit the notification as specified in 40 CFR 60.5420a(a)(2), submit annual reports as specified in 40 CFR 60.5420a(b)(1) and (2) and maintain records specified in 40 CFR 60.5420a(c)(1)(iii) for each wildcat and delineation well. You must submit the notification as specified in 40 CFR 60.5420a(a)(2), submit annual reports as specified in 40 CFR 60.5420a(b)(1) and (2), and maintain records as specified in 40 CFR 60.5420a(c)(1)(iii) and (vii) for each low pressure well.	Yes	Reasonable Inquiry/Record Review
	40 CFR 60.5375a(g)	NSPS Subpart OOOOa Well Affected Facility	For each well affected facility with less than 300 scf of gas per stock tank barrel of oil produced, you must comply (1) and (2). (1) You must maintain records specified in 40 CFR 60.5420a(c)(1)(vi). (2) You must submit reports specified in 40 CFR 60.5420a(b)(1) and (2).	Yes	Reasonable Inquiry/Record Review
	40 CFR 60.5397a(a)	NSPS Subpart OOOOa Fugitive Emission Components at a Well Site	Monitor all fugitive emission components, as defined in 40 CFR 60.5430a, in accordance with 40 CFR 60.5397a(b) through (g). You must repair all sources of fugitive emissions in accordance with 40 CFR 60.5397a(h). You must keep records in accordance with 40 CFR 60.5397a(i) and report in accordance with 40 CFR 60.5397a(j). Fugitive emissions are defined as: Any visible emission from a fugitive emissions component observed using optical gas imaging or an instrument reading of 500 ppm or greater using Method 21.	Yes	Reasonable Inquiry/Record Review
	40 CFR 60.5397a(b)	NSPS Subpart OOOOa Fugitive Emission Components at a Well Site	Develop an emissions monitoring plan that covers the collection of fugitive emissions components at well sites within each company-defined area in accordance with 40 CFR 60.5397a(c) and (d).	Yes	Reasonable Inquiry/Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
	40 CFR 60.5397a(c)	NSPS Subpart OOOOa Fugitive Emission Components at a Well Site Continued below	Fugitive emissions monitoring plans must include the elements specified (1) through (8), at a minimum. (1) Frequency for conducting surveys. Surveys must be conducted at least as frequently as required by 40 CFR 60.5397a(f) and (g). (2) Technique for determining fugitive emissions (i.e., Method 21 at 40 CFR part 60, appendix A–7, or optical gas imaging). (3) Manufacturer and model number of fugitive emissions detection equipment to be used. (4) Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of 40 CFR 60.5397a(h) at a minimum. (5) Procedures and timeframes for verifying fugitive emission component repairs. (6) Records that will be kept and the length of time records will be kept. (7) If you are using optical gas imaging, your plan must also include the elements specified in (7)(i) through (vii). (7)(i) Verification that your optical gas imaging equipment meets the specifications of (7)(i)(A) and (B). This verification is an initial verification and may either be performed by the facility, by the manufacturer, or by a third party. For the purposes of complying with the fugitives emissions monitoring program with optical gas imaging, a fugitive emission is defined as any visible emissions observed using optical gas imaging.	Yes	Reasonable Inquiry/Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
	40 CFR 60.5397a(c)	NSPS Subpart OOOOa Fugitive Emission Components at a Well Site (Continued below)	(7)(i)(A) Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions. (7)(i)(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤60g/hr from a quarter inch diameter orifice. (7)(ii) Procedure for a daily verification check. (7)(iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained. (7)(iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold. (7)(v) Procedures for conducting surveys, including the items specified in (7)(v)(A) through (C). (7)(v)(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions. (7)(v)(B) How the operator will deal with adverse monitoring conditions, such as wind. (7)(v)(C) How the operator will deal with interferences (e.g., steam). (7)(vi) Training and experience needed prior to performing surveys. (7)(vii) Procedures for calibration and maintenance. At a minimum, procedures must comply with those recommended by the manufacturer.	Yes	Reasonable Inquiry/Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
	40 CFR 60.5397a(c)	NSPS Subpart OOOOa Fugitive Emission Components at a Well Site (Continued)	(8) If you are using Method 21 of appendix A–7 of this part, your plan must also include the elements specified in (8)(i) and (ii). For the purposes of complying with the fugitive emissions monitoring program using Method 21 a fugitive emission is defined as an instrument reading of 500 ppm or greater. (8)(i) Verification that your monitoring equipment meets the requirements specified in Section 6.0 of Method 21 at 40 CFR part 60, appendix A–7. For purposes of instrument capability, the fugitive emissions definition shall be 500 ppm or greater methane using a FID-based instrument. If you wish to use an analyzer other than a FID-based instrument, you must develop a site- specific fugitive emission definition that would be equivalent to 500 ppm methane using a FID-based instrument (e.g., 10.6 eV PID with a specified isobutylene concentration as the fugitive emission definition would provide equivalent response to your compound of interest). (8)(ii) Procedures for conducting surveys. At a minimum, the procedures shall ensure that the surveys comply with the relevant sections of Method 21 at 40 CFR part 60, appendix A–7, including Section 8.3.1.	Yes	Reasonable Inquiry/Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
	40 CFR 60.5397a(d)	NSPS Subpart OOOOa Fugitive Emission Components at a Well Site	Each fugitive emissions monitoring plan must include the elements specified in (1) through (4), at a minimum, as applicable. (1) If you are using optical gas imaging, your plan must include procedures to ensure that all fugitive emissions components are monitored during each survey. Example procedures include, but are not limited to, a sitemap with an observation path, a written narrative of where the fugitive emissions components are located and how they will be monitored, or an inventory of fugitive emissions components. (2) If you are using Method 21, your plan must also include a list of fugitive emissions components to be monitored and method for determining location of fugitive emissions components to be monitored in the field (e.g. tagging, identification on a process and instrumentation diagram, etc.). (3) Your plan must also include the written plan developed for all of the fugitive emission components designated as difficult-to-monitor in accordance with 40 CFR 60.5397a(g)(3), and the written plan for fugitive emission components designated as unsafe-to-monitor in accordance with 40 CFR 60.5397a(g)(4).	Yes	Reasonable Inquiry/Record Review
	40 CFR 60.5397a(e)	NSPS Subpart OOOOa Fugitive Emission Components at a Well Site	Each monitoring survey shall observe each fugitive emissions component, as defined in 40 CFR 60.5430a, for fugitive emissions.	Yes	Reasonable Inquiry/Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
	40 CFR 60.5397a(f)	NSPS Subpart OOOOa Fugitive Emission Components at a Well Site	Conduct an initial monitoring survey within 60 days of the startup of production, as defined in 40 CFR 60.5430a, for each collection of fugitive emissions components at a new well site or by June 3, 2017, whichever is later. For a modified collection of fugitive emissions components at a well site, the initial monitoring survey must be conducted within 60 days of the first day of production for each collection of fugitive emission components after the modification or by June 3, 2017, whichever is later.	Yes	Reasonable Inquiry/Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
	40 CFR 60.5397a(g)	NSPS Subpart OOOOa Fugitive Emission Components at a Well Site (Continued below)	A monitoring survey of each collection of fugitive emissions components at a well site must be performed at the frequency specified in (1), with the exceptions noted in (2) and (3). (1) A monitoring survey of each colletion of fugitive emissions components at a well site located on the Alaskan North Slope must be conducted at least annually. Consecutive annual monitoring surveys must be conducted at least 9 months apart and no more than 13 months apart. (2) Fugitive emissions components that cannot be monitored without elevating the monitoring personnel more than 2 meters above the surface may be designated as difficult-to- monitor. Fugitive emissions components that are designated difficult-to-monitor must meet the specifications of (2)(i) through (iv). (2)(i) A written plan must be developed for all of the fugitive emissions components designated difficult-to- monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by 40 CFR 60.5397a(b), (c), and (d). (2)(ii) The plan must include the identification and location of each fugitive emissions component designated as difficult-to-monitor. (2)(iii) The plan must include an explanation of why each fugitive emissions component designated as difficult-to-monitor is difficult-to- monitor. (2)(iv) The plan must include a schedule for monitoring the difficult-to-monitor fugitive emissions components at least once per calendar year.	Yes	Reasonable Inquiry/Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
	40 CFR 60.5397a(g)	NSPS Subpart OOOOa Fugitive Emission Components at a Well Site Continued	(3) Fugitive emissions components that cannot be monitored because monitoring personnel would be exposed to immediate danger while conducting a monitoring survey may be designated as unsafe-to-monitor. Fugitive emissions components that are designated unsafe- to-monitor must meet the specifications of (3)(i) through (iv). (3)(i) A written plan must be developed for all of the fugitive emissions components designated unsafe-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by 40 CFR 60.5397a(b), (c), and (d). (3)(ii) The plan must include the identification and location of each fugitive emissions component designated as unsafe-to-monitor. (3)(iii) The plan must include an explanation of why each fugitive emissions component designated as unsafe-to-monitor is unsafe-to-monitor. (3)(iv) The plan must include a schedule for monitoring the fugitive emissions components designated as unsafe-to- monitor.	Yes	Reasonable Inquiry/Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
	40 CFR 60.5397a(h)	NSPS Subpart OOOOa Fugitive Emission Components at a Well Site (Continued below)	Each identified source of fugitive emissions shall be repaired or replaced in accordance with (1) and (2). (1) Each identified source of fugitive emissions shall be repaired or replaced as soon as practicable, but no later than 30 calendar days after detection of the fugitive emissions. (2) If the repair or replacement is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next compressor station shutdown, well shutdown, well shut-in, after an unscheduled, planned or emergency vent blowdown or within 2 years, whichever is earlier. (3) Each repaired or replaced fugitive emissions component must be resurveyed as soon as practicable, but no later than 30 days after being repaired, to ensure that there are no fugitive emissions. (3)(i) The Permittee may resurvey the fugitive emissions components to verify repair using either Method 21 of Appendix A-7 of 40 CFR 60 or optical gas imaging. (3)(ii) For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken, must clearly identify the component by location within the site (e.g., the latitude and longitude of the component or by other descriptive landmarks visible in the picture).	Yes	Reasonable Inquiry/Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
	40 CFR 60.5397a(h) Continued	NSPS Subpart OOOOa Fugitive Emission Components at a Well Site	(3)(iii) Operators that use Method 21 to resurvey the repaired fugitive emissions components are subject to the resurvey provisions specified in (3)(iii)(A) and (B). (3)(iii)(A) A fugitive emissions component is repaired when the Method 21 instrument indicates a concentration of less than 500 ppm above background or when no soap bubbles are observed when the alternative screening procedures specified in section 8.3.3 of Method 21 are used. (3)(iii)(B) Operators must use the Method 21 monitoring requirements specified in 40 CFR 60.5397a(c)(8)(ii) or the alternative screening procedures specified in section 8.3.3 of Method 21. (3)(iv) Operators that use optical gas imaging to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in (3)(iv)(A) and (B). (3)(iv)(A) A fugitive emissions component is repaired when the optical gas imaging instrument shows no indication of visible emissions. (3)(iv)(B) Operators must use the optical gas imaging monitoring requirements specified in 40 CFR 60.5397(c)(7).	Yes	Reasonable Inquiry/Record Review
	40 CFR 60.5397a(i)	NSPS Subpart OOOOa Fugitive Emission Components at a Well Site	Records for each monitoring survey shall be maintained as specified 40 CFR 60.5420a(c)(15).	Yes	Reasonable Inquiry/Record Review
	40 CFR 60.5397a(j)	NSPS Subpart OOOOa Fugitive Emission Components at a Well Site	Annual reports shall be submitted for each collection of fugitive emissions components at a well site that include the information specified in 40 CFR 60.5420a(b)(7). Multiple collections of fugitive emissions components at a well site may be included in a single annual report.	Yes	Reasonable Inquiry/Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
	40 CFR 60.5410a	NSPS Subpart OOOOa Well Affected Facility	The initial compliance period begins on August 2, 2016, or upon initial startup, whichever is later, and ends no later than 1 year after the initial startup date for your affected facility or no later than 1 year after August 2, 2016. The initial compliance period may be less than one full year.	Yes	Reasonable Inquiry/Record Review
	40 CFR 60.5410a(a)	NSPS Subpart OOOOa Well Affected Facility (Continued below)	To achieve initial compliance with the methane and VOC standards for each well completion operation conducted at your well affected facility you must comply with (1) through (4). (1) You must submit the notification required in 40 CFR 60.5420a(a)(2). (2) You must submit the initial annual report for your well affected facility as required in 40 CFR 60.5420a(b)(1) and (2). (3) You must maintain a log of records as specified in 40 CFR 60.5420a(c)(1)(i) through (iv), as applicable, for each well completion operation conducted during the initial compliance period. If you meet the exemption for wells with a GOR less than 300 scf per stock barrel of oil produced, you do not have to maintain the records in 40 CFR 60.5420a(c)(1)(i) through (iv) and must maintain the record in 40 CFR 60.5420a(c)(1)(vi).	Yes	Reasonable Inquiry/Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
	40 CFR 60.5410a(a)	NSPS Subpart OOOOa Well Affected Facility (Continued)	(4) For each well affected facility subject to both 40 CFR 60.5375a(a)(1) and (3), as an alternative to retaining the records specified in 40 CFR 60.5420a(c)(1)(i) through (iv), you may maintain records in accordance with 40 CFR 60.5420a(c)(1)(v) of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file showing the equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to the gas flow line and the completion combustion device (if applicable) connected to and operating at each well completion operation that occurred during the initial compliance period. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the equipment connected and operating at each well completion operation with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.	Yes	Reasonable Inquiry/Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
	40 CFR 60.5410a(j)	NSPS Subpart OOOOa Fugitive Emission Components at a Well Site	To achieve initial compliance with the fugitive emission standards for each collection of fugitive emissions components at a well site, comply with (1) through (5). (1) You must develop a fugitive emissions monitoring plan as required in 40 CFR 60.5397a(b), (c), and (d). (2) You must conduct an initial monitoring survey as required in 40 CFR 60.5397a(f). (3) You must maintain the records specified in 40 CFR 60.5420a(c)(15). (4) You must repair each identified source of fugitive emissions for each affected facility as required in 40 CFR 60.5397a(h). (5) You must submit the initial annual report for each collection of fugitive emissions components at a well site as required in 40 CFR 60.5420a(b)(1) and (7).	Yes	Reasonable Inquiry/Record Review
	40 CFR 60.5415a(a)	NSPS Subpart OOOOa Well Affected Facility	Demonstrate continuous compliance by submitting the reports required by 40 CFR 60.5420a(b)(1) and (2) and maintaining the records for each completion operation specified in 40 CFR 60.5420a(c)(1).	Yes	Reasonable Inquiry/Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
	40 CFR 60.5415a(h)	NSPS Subpart OOOOa Fugitive Emission Components at a Well Site	For each collection of fugitive emissions components at a well site, you must demonstrate continuous compliance with the fugitive emission standards specified in 40 CFR 60.5397a according to (1) through (4). (1) You must conduct periodic monitoring surveys as required in 40 CFR 60.5397a(g). (2) You must repair or replace each identified source of fugitive emissions as required in 40 CFR 60.5397a(h). (3) You must maintain records as specified in 40 CFR 60.5420a(c)(15). (4) You must submit annual reports for collection of fugitive emissions components at a well site as required in 40 CFR 60.5420a(b)(1) and (7).	Yes	Reasonable Inquiry/Record Review
	40 CFR 60.5420a(a)	NSPS Subpart OOOOa Notification Requirements	Submit the notifications according to 40 CFR 60.5420a(a)(2).	Yes	Reasonable Inquiry/Record Review

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
	40 CFR 60.5420a(b)	NSPS Subpart OOOOa Reporting Requirements	Submit annual reports containing the information specified in 40 CFR 60.5420a(b)(1), (2), (7) and (12), as applicable. Submit annual reports following the procedure specified in 40 CFR 60.5420(b)(11). The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to 40 CFR 60.5410a. Subsequent annual reports are due no later than same date each year as the initial annual report. If the Permittee owns or operates more than one affected facility, one report may be submitted for multiple affected facilities provided the report contains all of the information required as specified in 40 CFR 60.5420a(b)(1) and (2). Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. The Permittee may arrange with the Administrator a common schedule on which reports required by 40 CFR 60 may be submitted as long as the schedule does not extend the reporting period.	Yes	Reasonable Inquiry/Record Review
	40 CFR 60.5420a(c)	NSPS Subpart OOOOa Recordkeeping Requirements	Maintain the records identified as specified in 40 CFR 60.7(f) and in 40 CFR 60.5375a(c)(1) and (c)(15). All records required by 40 CFR 60 Subpart OOOOa must be maintained either onsite or at the nearest local field office for at least 5 years. Any records required to be maintained by 40 CFR 60 Subpart OOOOa that are submitted electronically via the EPA's CDX may be maintained in electronic format.	Yes	Reasonable Inquiry/Record Review
	40 CFR 60.5425a	NSPS Subpart OOOOa General Requirement	Table 3 to 40 CFR 60 Subpart OOOOa shows which parts of the General Provisions in 40 CFR 60.1 through 60.19 apply.	Yes	Reasonable Inquiry/Record Review

[1]Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM E4
Permit Shield Request

Permit Number: AQ0417TVP03

Non-applicable requirements (*attach additional sheets as needed*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60 Subpart Kb	All storage tanks either meet 40 CFR 60.110b(b), which exempts tanks that have a capacity greater than 151 cubic meters storing a liquid with a maximum true vapor pressure less than 3.5 kPa or with a capacity greater than 75 cubic meters but less than 151 cubic meters storing a liquid with a maximum true vapor pressure less than 15 kPa, or do not meet the applicability requirements in 40 CFR 60.110b(a).
40 CFR 60 Subparts AAAA, CCCC, and EEEE	Incinerators have not commenced construction, modification, or reconstruction after August 30, 1999.
40 CFR 60 Subpart OOOO	Gas wells and other applicable equipment were constructed prior to August 23, 2011.
40 CFR 60 Subpart OOOOa – Compressors	Stationary source has two reciprocating compressors that were installed prior to September 18, 2015. The units have not been modified or reconstructed.
40 CFR 60 Subpart OOOOa – Storage Vessels	Stationary source does not have any applicable storage tanks that have been installed, modified, or reconstructed after September 18, 2015.
40 CFR 60 Subpart OOOOa – Pneumatic Controllers, Pneumatic Pumps, and Sweetening Units	Stationary source does not have any natural gas pneumatic devices or sweetening units.
40 CFR 60 Subpart OOOOa – Process Units	Stationary source is not an onshore natural gas processing plant as defined in Subpart OOOOa.
40 CFR 61 Subpart J	Stationary source does not contain any equipment in benzene service (≥10% by weight).
40 CFR 61 Subpart V	Stationary source does not operate equipment in volatile hazardous air pollutant (VHAP) service, as defined under 40 CFR 61.241 (≥10 percent VHAP by weight).
40 CFR 61 Subpart Y	Stationary source does not operate storage vessels in benzene service.
40 CFR 61 Subpart BB	Stationary source does not conduct benzene transfer operations.
40 CFR 61 Subpart FF	Stationary source does not conduct benzene water operations.
40 CFR 61.05(a), 61.07, 61.09, 61.10, 61.13, 61.14	Stationary source is a demolition and renovation operation and is exempt from these requirements.
40 CFR 61.142, 61.149	Stationary source is not an asbestos mill.
40 CFR 61.143	Stationary source roadways not exposed to asbestos tailings or asbestos containing waste.
40 CFR 61.144	Stationary source does not engage in any manufacturing operations using commercial asbestos.
40 CFR 61.146	Stationary source does not spray apply asbestos containing materials.
40 CFR 61.147	Stationary source does not engage in any fabricating operations using commercial asbestos.

40 CFR 61.148	Stationary source does not install or reinstall, on any facility component, insulation material containing commercial asbestos.
40 CFR 61.151	Applies only to those stationary sources subject to 40 CFR 61.142, 61.144, or 61.147.
40 CFR 61.152	Stationary source does not use air cleaning equipment.
40 CFR 61.153	No reporting requirements apply for sources subject to 40 CFR 61.145.
40 CFR 61.154	Stationary source not an active waste disposal site and does not receive asbestos containing waste material.
40 CFR 61.155	Stationary source does not process regulated asbestos containing material.
40 CFR 63 Subpart HH	The stationary source exclusively processes, stores, or transfers black oil (63.760(e)(1)).
40 CFR 68	Stationary source does not have more than the threshold quantity of a regulated substance in a process.
40 CFR 82 Subpart B	Stationary source and its employees do not perform service on motor vehicle air conditioners, for consideration or otherwise.
18 AAC 50.050(b)	The PM standard does not apply to incinerators with a rated capacity less than 1,000 pounds per hour.
18 AAC 50.055	The standards do not apply to the non-road engines or incinerators. The non-road engines and incinerators are not “industrial processes” or “fuel burning equipment” as defined in 18 AAC 50.990(39) or (49).
40 CFR 60 Subpart D, Da, Db, Dc	Heaters included as insignificant emission units do not exceed the minimum threshold (10 MMBtu/hr).
40 CFR 63 Subpart JJJJJJ	Heaters are not subject to Subpart JJJJJJ (insignificant emission units).

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM E5

Alternative Monitoring Procedures (AMP) Form

Permit Number: AQ0417TVP03

Stationary Source-Wide Alternative Monitoring Procedures and/or EPA Waivers (*attach additional sheets as needed*):

Condition for which AMP or EPA waiver is applicable	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
Condition 30	Sulfur Dioxide	NSPS Subpart Dc	Yes	Condition 30.1
Condition 34.1d(i)	Sulfur Dioxide	NSPS Subpart GG	Yes	Condition 34.1d(ii)(B), 34.3, 34.4

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

U.S. Environmental Protection Agency
Applicability Determination Index

Control Number: 0300089

Category: NSPS
EPA Office: Region 10
Date: 02/03/1999
Title: Alternative Recordkeeping Plan
Recipient: Janet Platt
Author: Raymond Nye

Subparts: Part 60, Dc, Small Indust.-Comm.-Inst. Steam Gen. Units

---

References: 60.48c(g)

Abstract:

Q: May BPXA record fuel usage quarterly rather than daily as prescribed in Sec. 60.48c(g) for two heaters at the Badami Project?

A: Yes. Because Subpart Dc contains no emission limit for steam generating units combusting only natural gas fuels, EPA approves the request to record fuel usage quarterly. This approval becomes void if the heaters combust a fuel other than natural gas.

Letter:

Reply To
Attn Of: OAQ-107

Ms. Janet D. Platt
Supervisor, Environmental Compliance
HSE Alaska
BP Exploration (Alaska) Inc.
P.O. Box 196612
Anchorage, Alaska 99519-6612

Dear Ms. Platt:

This letter is in response to your November 11, 1998, request for approval of alternative recordkeeping requirements for two heaters at Badami Development Project located on the North Slope of Alaska. A 34 MMBtu per hour production heater and a 15 MMBtu per hour miscible injection heater are subject to 40 C.F.R. Part 60, Subpart Dc - Standards of Performance for Small Industrial - Commercial - Institutional Steam Generating Units. You propose to record each heater's fuel usage quarterly rather than daily as prescribed in Sec. 60.48c(g).

Based upon information provided to EPA Region 10, each heater operates continuously with the capacity to combust pipeline quality natural gas. Since Subpart Dc contains no emission limit for steam generating units combusting only natural gas fuels, EPA Region 10 has determined that a relaxation of the recordkeeping requirements is appropriate in this instance. Therefore, EPA Region 10 approves your request to record fuel usage quarterly.

In the event BP Exploration elects to combust a fuel other than natural gas, this approval becomes void and you shall be required to record fuel usage daily in accordance with Sec. 60.48c(g). This waiver does not alter any other requirements of Subpart Dc.

If you have any questions, please contact Daniel Meyer of this office at 206-553-4150.

Sincerely,

Raymond Nye
Federal and Delegated Air Programs

cc: Ms. Alison Cooke, BP Exploration (Alaska) Inc. Mr. John A. Pavitt, USEPA Region 10 - Alaska Operations Office Mr. John Stone, ADEC - Juneau

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue
Seattle, Washington 98101

NOV 12 1998

Copy: Badami ACS Env. Spec. c. Alison Cooke
Mike Goodwin / John Powers Sean Leonard
Pat Nair - Radian John Booth
Debby Oyleax Rtn: JPlatt
File: 601.06

Reply To
Attn Of: OAQ-107

Ms. Janet D. Platt
BP Exploration (Alaska) Inc. (BPX Alaska)
900 East Benson Boulevard
Anchorage, Alaska 99519-6612

Re: Alternative Monitoring Plan (AMP) for Turbines at Badami Development Project

Dear Ms. Platt:

This letter responds to your September 14, 1998, request for an AMP for BPX Alaska's facility at the Badami Development Project, located on the North Slope of Alaska. Your request is pursuant to 40 CFR 60.334 (a)(2), Standards of Performance for Stationary Gas Turbines, and applies to the two Solar, Mars 90 natural gas turbines, tag numbers GT-0001A and GT-0001B.

Authorization has been delegated to the Environmental Protection Agency regional offices to approve New Source Performance Standards (NSPS) Subpart GG AMPs on a case-by-case basis. EPA Region 10 approves the AMP for the turbines listed above according to the attached requirements.

The attached AMP for fuel gas does not alter any of the other requirements of NSPS Subparts A and GG which may apply to the facility. All reports should be addressed to this office. If you have any questions regarding this alternate monitoring schedule, please call Cynthia Walcker at (206) 553-2710.

Sincerely,

[signature]

Gil Haselberger, Unit Manager
Office of Air Quality
Air Enforcement & Program Support

Enclosure

cc: John Stone, ADEC

ENVIRONMENTAL
NOV 16 1998
& REG. AFFAIRS

U.S. Environmental Protection Agency Region 10
Alternative Monitoring Plan

November 9, 1998

Applicability

This alternative monitoring plan applies to the two Solar, Mars 90 turbines, tag numbers GT-0001A and GT-0001B, operated by BP Exploration at Badami Development Project. All other requirements of 40 C.F.R. Part 60 Subparts A and GG apply.

Sulfur Monitoring

BP Exploration shall monitor the sulfur content of the natural gas used at least quarterly for 6 calendar quarters.

If sulfur monitoring determines that sulfur levels of the natural gas are always below 80 ppm, measured as H_2S, then BP Exploration shall monitor sulfur content of the natural gas at least semi-annually.

Nitrogen Monitoring

Nitrogen monitoring shall be waived for fuel gas.

Record Keeping

BP Exploration shall maintain records of all sulfur monitoring data.

BP Exploration shall maintain a record documenting the source of natural gas. A substantial change in natural gas quality shall be considered as a change in fuel supply.

BP Exploration shall maintain a record of all turbine operation on all fuels other than fuel gas.

BP Exploration shall maintain records on-site for a period of 5 years from the generation of such record.

Reporting

BP Exploration shall annually report results of all sulfur monitoring.

BP Exploration shall report any changes in supplier or source of fuel within 60 days of such a change.

BP Exploration shall report use of any fuel used other than fuel gas.

ATTACHMENT
PERMIT NO. AQ0417TVP03

DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY OPERATING PERMIT

Permit No. AQ0417TVP03

Issue Date: September 13, 2018
Expiration Date: September 13, 2023

The Alaska Department of Environmental Conservation, under the authority of AS 46.14 and 18 AAC 50, issues an operating permit to the Permittee, **Savant Alaska, LLC (Savant)**, for the operation of the **Badami Development Facility**.

This permit satisfies the obligation of the owner and operator to obtain an operating permit as set out in AS 46.14.130(b).

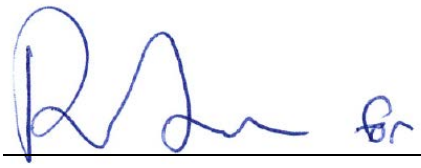
As set out in AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this operating permit.

All stationary source-specific terms and conditions of Minor Permit Nos. AQ0417MSS05, AQ0417MSS06, and AQ0417MSS07 Revision 1 have been incorporated into this permit.

Citations listed herein are contained within the effective version of 18 AAC 50 at permit issuance. All federal regulation citations are from those sections adopted by reference in this version of regulation in 18 AAC 50.040 unless otherwise specified.

Upon effective date of this permit, Operating Permit No. AQ0417TVP02 Revision 2 expires.

This Operating Permit becomes effective October 13, 2018.



James R. Plosay, Manager
Air Permits Program

Table of Contents

Abbreviations Used in this Permit

AAC.....Alaska Administrative Code
ADEC .....Alaska Department of Environmental Conservation
Administrator.....EPA and the Department.
AS .....Alaska Statutes
ASTM .....American Society for Testing and Materials
BACT .....Best Available Control Technology
bHp .....brake horsepower
C.F.R. .....Code of Federal Regulations
CI ICE.....Compression Ignition Internal Combustion Engine
CAA or The Act .Clean Air Act
CISWI.....Commercial and Industrial Solid Waste Incineration
CO .....Carbon Monoxide
CO_2e .....CO_2-equivalent
Department .....Alaska Department of Environmental Conservation
dscf .....Dry standard cubic foot
EPA .....US Environmental Protection Agency
EU.....Emissions unit
FAHS.....Federal Aid Highway System
GHG .....Greenhouse Gas
g/kW-hr.....gram per kilowatt-hour
gr/dscf.....grain per dry standard cubic foot (1 pound = 7000 grains)
gph.....gallons per hour
HAPs .....Hazardous Air Pollutants [HAPs as defined in AS 46.14.990]
Hp.....Horsepower
ID.....Emissions unit Identification Number
ISO.....International Organization for Standardization (Operating conditions corresponding to sea level and 59 deg. F)
IUOSE .....intermittently used oilfield equipment
kPa.....kiloPascals
kW .....kiloWatt
kW-e .....kiloWatts electric
LAER.....Lowest Achievable Emission Rate
MACT .....Maximum Achievable Control Technology [MACT as defined in 40 C.F.R. 63]
MMBtu/hr .....Million British thermal units per hour
MMscf.....Million standard cubic feet
MR&R.....Monitoring, Recordkeeping, and Reporting
NAICS.....North American Industrial Classification System
N/A.....Not Available; Not Applicable
NESHAPs.....Federal National Emission Standards for Hazardous Air Pollutants [NESHAPs as contained in 40 C.F.R. 61 and 63]
NGP.....Natural Gas Producer
NH_3.....ammonia
NOx.....Nitrogen Oxides
NSPS .....Federal New Source Performance Standards [NSPS as contained in 40 C.F.R. 60]
O & M .....Operation and Maintenance
O_2 .....Oxygen
PAL .....Plantwide Applicability Limitation
Pb .....lead
PM-10 .....Particulate Matter less than or equal to a nominal ten microns in diameter
ppm .....Parts per million
ppmv, ppmvd .....Parts per million by volume on a dry basis
psia .....Pounds per Square Inch (absolute)
PSD .....Prevention of Significant Deterioration
PTE .....Potential to Emit
RICE .....Reciprocating Internal Combustion Engine
SIC. .....Standard Industrial Classification
SIP.....State Implementation Plan
SPC .....Standard Permit Condition or Standard Operating Permit Condition
SO_2 .....Sulfur dioxide
TEG.....Triethylene glycol
TPH.....Tons per hour
TPY .....Tons per year

TPD ..... Tons per day

ULSD ..... Ultra-Low Sulfur Diesel

VE ..... visible emissions

VOC ..... volatile organic compound [VOC as defined in 40 C.F.R. 51.100(s)]

VOL ..... volatile organic liquid [VOL as defined in 40 C.F.R. 60.111b, Subpart Kb]

vol% ..... volume percent

wt% ..... weight percent

$wt\%S_{fuel}$ ..... weight percent of sulfur in fuel

Section 1. Stationary Source Information

Identification

Permittee:	**Savant Alaska, LLC** 601 W. 5th Avenue, Suite 310 Anchorage, Alaska 99501
Stationary Source Name:	**Badami Development Facility**
Location:	UTM Zone 6, Northing 7782.6 km, Easting 494.6 km Latitude: 70° 09' 03.62" N Longitude: 147° 05' 50.05" W
Physical Address:	Badami Unit, North Slope, Alaska
Owner:	**Savant Alaska, LLC** 601 W. 5th Avenue, Suite 310 Anchorage, Alaska 99501
Operator:	**Savant Alaska, LLC** 601 W. 5th Avenue, Suite 310 Anchorage, Alaska 99501
Responsible Official:	Leland Tate, Senior Vice President/COO 601 W. 5th Avenue, Suite 310 Anchorage, Alaska 99501
Designated Agent:	Stoel Rives LLP Ramona L. Monroe, Attorney 600 University Street, Suite 3600 Seattle, Washington 98101-4109
Stationary Source/ Building Contact:	Jennifer Henderson, Regulatory & Compliance Manager 601 W. 5th Avenue, Suite 310 Anchorage, Alaska 99501 (907) 433-3807 JHenderson@glacieroil.com
Fee and Permit Contact:	Jennifer Henderson, Regulatory & Compliance Manager 601 W. 5th Avenue, Suite 310 Anchorage, Alaska 99501 (907) 433-3807 JHenderson@glacieroil.com
Process Description SIC Code: NAICS Code:	1311 - Crude Petroleum and Natural Gas 211111 - Crude Petroleum and Natural Gas Extraction

[18 AAC 50.040(j)(3) & 50.326(a)]
[40 C.F.R. 71.5(c)(1) & (2)]

Section 2. Emissions Unit Inventory and Description

Emissions units listed in Table A have specific monitoring, recordkeeping, or reporting (MR&R) conditions in this permit. Unless noted elsewhere in the permit, emissions unit descriptions and ratings are given for identification purposes only.

Table A - Emissions Unit Inventory

EU ID	Emissions Unit Name	Emissions Unit Description[c]	Fuel	Rating/Size	Installation or Construction Date
420a[a]	Generator	Cummins QSK50-G4 SN 25384677	Diesel	1,971 Hp	Constructed in 2012; Installed in April 2013
421a[b]	Generator	Cummins QSK50-G4 SN 33183042	Diesel	1,971 Hp	Constructed in 2010; Installed April 5, 2011.
500	Turbine	Solar Mars 90 SN 0456M	Fuel Gas[d]	11,862 kW	1998
501	Turbine	Solar Mars 90 SN 0455M	Fuel Gas	11,862 kW	1998
503	Production Heater	NATCO SN 5A300	Fuel Gas	34 MMBtu/hr	1998
505	TEG Reboiler	NATCO SN 8001-41	Fuel Gas	1.34 MMBtu/hr	1998
507	Flare	Mac Ignitor 100 Series	Fuel Gas and Produced Gas	257.9 MMscf/yr	1998
Drill Rig Equipment[e]					
1	Rig Engines	Various	Diesel/Fuel Gas	Various	Various
8	Rig Boilers and Heaters	Various	Diesel/Fuel Gas	Various	Various

Table Notes:

[a] EU ID 420a replaced EU ID 420; this replacement was an off-permit change allowed under 40 CFR 71.6(a)(12), adopted by reference in 18 AAC 50.326(j)(4).

[b] EU ID 421a replaced EU ID 421, authorized by Permit No. AQ0417MSS03 issued on October 20, 2010.

[c] SN means Serial Number

[d] *Fuel Gas*, as the term is used in this permit, is described by the definition of *Gaseous Fuel* found in 40 CFR 60.41b, Subpart Db: "*Gaseous fuel* means any fuel that is a gas at ISO conditions. This includes, but is not limited to, natural gas and gasified coal (including coke oven gas)."

[e] The Permittee is authorized to operate any of the drill rigs with a cumulative rating equal to or less than the largest approved drill rig in Operating Permit No. AQ0455TVP01, Revision 5 (or subsequent renewals or revisions).

[18 AAC 50.326(a)]
[40 C.F.R. 71.5(c)(3)]

Section 3. State Requirements

Visible Emissions Standard

1. Industrial Process and Fuel-Burning Equipment Visible Emissions. The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from EU IDs 8, 420a, 421a, 500, 501, 503, 505, and 507 listed in Table A to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.[1]

[18 AAC 50.040(j), 50.055(a)(1), & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]

1.1. For EU ID 8, monitor, record, and report in accordance with Condition 21.4.[2]

1.2. For EU IDs 420a and 421a, monitor, record and report in accordance with Conditions 2 through 4.

1.3. For EU IDs 500, 501, 503, and 505, burn only fuel gas as fuel. Monitoring for these emissions units shall consist of a statement in each operating report under Condition 71 indicating whether each of these emissions units burned only fuel gas during the period covered by the report. Report under Condition 70 if any fuel other than fuel gas is burned.

1.4. For EU ID 507, monitor, record and report in accordance with Condition 5.

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]

Visible Emissions Monitoring, Recordkeeping and Reporting (MR&R)

Liquid Fuel-Fired Emissions units (EU IDs 420a and 421a)

2. Visible Emissions Monitoring. As required by Conditions 1.2 or 18.4.a, the Permittee shall observe the exhaust of EU IDs 420a and 421a for visible emissions using the Method 9 Plan under Condition 2.3.

2.1. In the event of replacement of any of EU IDs 420a and 421a, the Permittee shall observe the exhaust of the newly installed emissions unit(s) using the Method 9 Plan under Condition 2.3.

2.2. The Permittee may for each unit elect to continue the visible emissions monitoring schedule that remain in effect from a previous permit.

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(i)]

[1] EU IDs 420a, 421a, 500, and 501 are also subject to more stringent BACT opacity limits in Condition 17.5.

[2] EU ID 8 consists of small rig boilers and heaters that are insignificant based on size and/or have potential and/or actual emissions below the significant emissions thresholds in 18 AAC 50.326(e). However, EU ID 8 does not qualify as insignificant unit per 18 AAC 50.326(d)(1) because it is subject to operational limits and standards established under a Title I permit. The Department referenced the general requirements for insignificant emissions units to satisfy the State VE and PM MR&R requirements for this unit.

2.3. **Method 9 Plan.** For all observations in this plan, observe emissions unit exhaust, following 40 C.F.R. 60, Appendix A-4, Method 9 for 18 minutes to obtain 72 consecutive 15-second opacity observations.[3]

a. **First Method 9 Observation.** Except as provided in Condition 2.2, observe the exhaust of EU IDs 420a and 421a for 18 minutes within six months after the issue date of this permit.

(i) For any of EU IDs 420a and 421a that is replaced during the term of this permit, observe exhaust for 18 minutes within 30 days of startup.

b. **Monthly Method 9 Observations**. After the first Method 9 observation conducted under Condition 2.3.a, perform 18-minute observations at least once in each calendar month that the emissions unit operates.

c. **Semiannual Method 9 Observations**. After at least three monthly observations under Condition 2.3.b, unless a six-minute average opacity is greater than 15 percent and one or more observations are greater than 20 percent, perform observations:

(i) within six months after the preceding observation, or

(ii) for an emissions unit with intermittent operations, during the next scheduled operation immediately following six months after the preceding observation.

d. **Annual Method 9 Observations.** After at least two semiannual observations under Condition 2.3.c, unless a six-minute average opacity is greater than 15 percent and one or more individual observations are greater than 20 percent, perform observations:

(i) within twelve months after the preceding observation; or

(ii) for an emissions unit with intermittent operations, during the next scheduled operation immediately following twelve months after the preceding observation.

e. **Increased Method 9 Frequency.** If a six-minute average opacity is observed during the most recent set of observations to be greater than 15 percent and one or more observations are greater than 20 percent, then increase or maintain the observation frequency for that emissions unit to at least monthly intervals as described in Condition 2.3.b, and continue monitoring in accordance with the Method 9 Plan.

[3] Emergency operations are exempt from the visible emission observation deadlines associated with emissions unit "operation" under this condition.

3. Visible Emissions Recordkeeping. When visible emissions monitoring is conducted, the Permittee shall keep records as follows:

[18 AAC 50.040(j); 50.326(j) & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(ii)]

3.1. For all Method 9 observations,

a. the observer shall record:

(i) the name of the stationary source, emissions unit and location, emissions unit type, observer's name and affiliation, and the date on the Visible Emissions Observation Form in Section 11;

(ii) the time, estimated distance to the emissions location, sun location, approximate wind direction, estimated wind speed, description of the sky condition (presence and color of clouds), and plume background, and operating rate *(load or fuel consumption rate or best estimate, if unknown)* on the sheet at the time opacity observations are initiated and completed;

(iii) the presence or absence of an attached or detached plume and the approximate distance from the emissions outlet to the point in the plume at which the observations are made;

(iv) opacity observations to the nearest five percent at 15-second intervals on the Visible Emissions Observation Form in Section 11, and

(v) the minimum number of observations required by the permit; each momentary observation recorded shall be deemed to represent the average opacity of emissions for a 15-second period.

3.2. To determine the six-minute average opacity, divide the observations recorded on the record sheet into sets of 24 consecutive observations; sets need not be consecutive in time and in no case shall two sets overlap; for each set of 24 observations, calculate the average by summing the opacity of the 24 observations and dividing this sum by 24; record the average opacity on the sheet.

3.3. Calculate and record the highest six-minute and 18-consecutive-minute average opacities observed.

3.4. The records may be kept in electronic format.

4. Visible Emissions Reporting. When visible emissions monitoring is conducted, the Permittee shall report visible emissions as follows:

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(iii)]

4.1. Include in each operating report under Condition 71:

a. copies of the observation results (i.e. opacity observations) for each emissions unit, except for the observations the Permittee has already supplied to the Department; and

b. a summary to include:

(i) number of days observations were made;

(ii) highest six- and 18-consecutive-minute average opacities observed; and

(iii) dates when one or more observed six-minute average opacities were greater than 20 percent; and

c. a summary of any monitoring or recordkeeping required under Conditions 2 and 3 that was not done.

4.2. Report under Condition 70:

a. the results of Method 9 observations that exceed 20 percent average opacity for any six-minute period; and

b. if any monitoring under Condition 2 was not performed when required, report within three days of the date the monitoring was required.

Flare (EU ID 507)

5. Visible Emissions MR&R. The Permittee shall observe one daylight flare event[4] within 12 months of the preceding flare event observation. If no event exceeds 1 hour within the 12-month period, then the Permittee shall observe the next daylight flare event.

5.1. Monitor the flare for visible emissions for 18 minutes during flare events using Method 9.

5.2. Record the following information for observed events:

a. the flare(s) EU ID number;

b. results of the Method 9 observations;

c. reason(s) for flaring;

d. date, beginning and ending time of event; and

e. volume of fuel gas and produced gas flared.

5.3. The records may be kept in electronic format.

5.4. Monitoring of a flare event may be postponed for safety or weather reasons, or because a qualified observer is not available. If monitoring of a flare event is postponed for any of the reasons described in this condition, the Permittee shall include in the next operating report required by Condition 71 an explanation of the reason the event was not monitored.

[4] For purposes of this permit, a *flare event* is flaring of fuel gas and produced gas for greater than one hour as a result of scheduled release operations, i.e. maintenance or well testing activities. It does not include non-scheduled release operations, i.e. process upsets, emergency flaring, or de-minimis venting of gas incidental to normal operations.

5.5. Attach copies of the records required by Condition 5.2 in the operating report required by Condition 71 for the period covered by that report.

5.6. Report under Condition 70 whenever the opacity standard in Condition 1 is exceeded.

[18 AAC 50.040(j) & 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3) & (c)(6)]

Particulate Matter Emissions Standards

6. Industrial Process and Fuel-Burning Equipment Particulate Matter. The Permittee shall not cause or allow particulate matter (PM) emitted from EU IDs 8, 420a, 421a, 500, 501, 503, 505, and 507 listed in Table A to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.

[18 AAC 50.040(j), 50.326(j), & 50.055(b)(1)]
[40 C.F.R. 71.6(a)(1)]

6.1. For EU ID 8, monitor, record, and report in accordance with Condition 21.4.[5]

6.2. For EU IDs 420a and 421a, monitor, record and report in accordance with Conditions 7 through 9.

6.3. For EU IDs 500, 501, 503, and 505, burn only fuel gas as fuel. Monitoring for these emissions units shall consist of a statement in each operating report under Condition 71 that each of these emissions units fired only fuel gas during the period covered by the report. Report under Condition 70 if any fuel other than fuel gas is burned.

6.4. For EU ID 507, the Permittee shall comply with Condition 5.

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)]

Particulate Matter MR&R

Liquid Fuel-burning Engines (EU IDs 420a and 421a)

7. Particulate Matter Monitoring. The Permittee shall conduct source tests on EU IDs 420a and 421a to determine the concentration of particulate matter in the exhaust of each emissions unit, as follows:

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(i)]

7.1. If any of EU IDs 420a and 421a exceeds the criteria of Conditions 7.2.a or 7.2.b, the Permittee shall, within six months of the exceedance, either:

a. except as exempted under Condition 7.4, conduct a particulate matter source test according to requirements set out in Section 6; or

[5] EU ID 8 consists of small rig boilers and heaters that are insignificant based on size and/or have potential and/or actual emissions below the significant emissions thresholds in 18 AAC 50.326(e). However, EU ID 8 does not qualify as insignificant unit per 18 AAC 50.326(d)(1) because it is subject to operational limits and standards established under a Title I permit. The Department referenced the general requirements for insignificant emissions units to satisfy the State VE and PM MR&R requirements for this unit.

b. make repairs and observe visible emissions as described in Condition 2.3 to show that emissions no longer exceed the criteria of Condition 7.2 under load conditions comparable to those when the criteria were exceeded.

7.2. Conduct the particulate matter source test or make repairs in accordance with Condition 7.1 if

a. Method 9 observations, as calculated under Condition 3.3, result in an 18-minute average opacity greater than 20 percent; or

b. for an emissions unit with an exhaust stack diameter that is less than 18 inches, Method 9 observations, as calculated under Condition 3.3, result in an 18-minute average opacity that is greater than 15 percent, unless the Department has waived this requirement in writing.

7.3. During each one-hour particulate matter source test run, observe the exhaust for 60 minutes in accordance with Method 9 and calculate the highest 18-minute average opacity measured during each one-hour test run. Submit a copy of these observations with the source test report.

7.4. The particulate matter source test requirements in Conditions 7.1 and 7.2 are waived for an emissions unit if a source test on that unit has shown compliance with the particulate matter standard during this permit term.

8. Particulate Matter Recordkeeping. The Permittee shall comply with the following:

8.1. Keep records of the results of any source test and visible emissions observations conducted under Condition 7.

8.2. In the event of replacement of any of EU IDs 420a and 421a, record the exhaust stack diameter of the replacement unit.

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(iii)]

9. Particulate Matter Reporting. The Permittee shall report as follows:

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(iii)]

9.1. Report under Condition 70:

a. if the results of any source test exceed the particulate matter emissions limit in Condition 6; or

b. if one of the criteria of Condition 7.2 was exceeded and the Permittee did not comply on time with either Condition 7.1.a or 7.1.b. Report the deviation within 24 hours of the date compliance with Condition 7.1 was required;

c. observations in excess of the threshold of Condition 7.2.b within 30 days of the end of the month in which the observations occur.

9.2. In each operating report under Condition 71, include:

a. the dates, EU ID(s), and results when an observed 18-minute average opacity was greater than an applicable threshold in Condition 7.2.

b. a summary of the results of any particulate matter testing conducted under Condition 7; and

c. copies of any visible emissions observation results greater than the thresholds of Condition 7.2, if they were not already submitted.

9.3. In the event of replacement of any of EU IDs 420a and 421a, report the stack diameter recorded in Condition 8.2 in the next operating report under Condition 71 immediately following installation of the replacement unit.

Sulfur Compound Emission Standards Requirements

10. Sulfur Compound Emissions. In accordance with 18 AAC 50.055(c), the Permittee shall not cause or allow sulfur compound emissions, expressed as SO_2, from EU IDs 8, 420a, 421a, 500, 501, 503, 505, and 507 listed in Table A to exceed 500 parts per million (ppm) averaged over three hours.

[18 AAC 50.040(j), 50.055(c), & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]

For Fuel Oil (EU IDs 8, 420a and 421a)

10.1. For EU IDs 8, 420a and 421a, to ensure compliance with Condition 10, the Permittee shall comply with the fuel sulfur content limit of 0.15 percent by weight as specified in Condition 14.[6]

a. The Permittee shall do one of the following for each shipment of fuel:

(i) If the fuel grade requires a sulfur content less than the 0.15 percent by weight limit, keep receipts that specify fuel grade and amount received; or

(ii) If the fuel grade does not require a sulfur content less than the 0.15 percent by weight limit, keep receipts that specify fuel grade and amount, and

(A) test the fuel for sulfur content using an appropriate method listed in 18 AAC 50.035(b)-(c) or 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1); or

(B) obtain test results showing the sulfur content of the fuel from the supplier or refinery; the test results must include a statement signed by the supplier or refinery of what fuel they represent.

10.2. The Permittee shall report as follows:

a. Include in each operating report required by Condition 71, records obtained under Condition 10.1.a.

[6] Compliance with the fuel oil sulfur content limit required in Condition 14 will assure compliance with the 500-ppm SO_2 emission limit of Condition 10.

b. Report in accordance with Condition 70, whenever the fuel combusted causes sulfur compound emissions to exceed the standard of Condition 10. When reporting under this condition, include the calculated SO_2 emissions in ppm using Method 19 of 40 C.F.R. 60, Appendix A-7, adopted by reference in 18 AAC 50.040(a).

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)]

For North Slope Liquid Fuel (EU IDs 8, 420a and 421a)

10.3. For liquid fuel from a North Slope topping plant, the Permittee shall obtain from the topping plant the results of a monthly fuel sulfur analysis.

10.4. The Permittee shall report as follows:

a. Include in the operating report required by Condition 71, a list of the sulfur content measured for each month covered by the report.

b. Report in accordance with Condition 70, whenever the fuel combusted causes sulfur compound emissions to exceed the standard of Condition 10. When reporting under this condition, include the calculated SO_2 emissions in ppm using Method 19 of 40 C.F.R. 60, Appendix A-7, adopted by reference in 18 AAC 50.040(a).

[18 AAC 50.040(j); 50.326(j); & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(iii)]

For Fuel Gas (EU IDs 8, 500, 501, 503, 505, and 507)

10.5. To ensure compliance with Condition 10, the Permittee shall comply with the fuel sulfur content limit of 250 parts per million by volume (ppmv) hydrogen sulfide (H_2S) content as specified in Condition 13.[7]

10.6. The Permittee shall either:

a. obtain a semiannual[8] statement from the fuel supplier of the fuel sulfur content in ppm; or

b. analyze a representative sample of the fuel semiannually[9] to determine the sulfur content using either ASTM D4084, D5504, D4810, D4913, D6228 or GPA Standard 2377, or a listed method approved in 18 AAC 50.035(b)-(c) and 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1).

10.7. The Permittee shall keep records of the sulfur content analysis required under Condition 10.6.a or 10.6.b.

[7] Compliance with the fuel gas H_2S content limit required in Condition 13 will assure compliance with the 500-ppm SO_2 emission limit of Condition 10.

[8] The EPA-approved Alternative Monitoring Plan (AMP, 11/12/98) under NSPS Subpart GG Condition 34.1.c requires quarterly monitoring for six calendar quarters, then reduced monitoring to semiannually if H_2S results are below 80 ppm.

[9] Refer to Footnote 8.

10.8. The Permittee shall report as follows:

a. Include copies of the records required by Condition 10.7 with the operating report required by Condition 71 for the period covered by the report.

b. Report in accordance with Condition 70, whenever the fuel combusted causes sulfur compound emissions to exceed the standard of Condition 10.

[18 AAC 50.040(j) & 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3) & (c)(6)]

Title I Permit Requirements

Limits to Protect Ambient Air Quality Standards

11. Fuel Gas and Produced Gas Flaring Limits, EU ID 507. Flare fuel gas and produced gas during routine or non-routine maintenance activities and other planned events. The Permittee shall flare fuel gas and produced gas quantities no greater than 152 MMscf of fuel gas and produced gas during any 12 consecutive-month period, at a rate of no greater than 20 MMscf per day.

11.1. Record the date and duration when fuel gas and produced gas flaring occurs and the quantity of fuel gas and produced gas flared.

11.2. Report in the operating report required by Condition 71, the date and duration of fuel gas and produced gas flaring and the total quantity of fuel gas and produced gas flared during the applicable reporting period; describe or document whether the flaring incident is considered an emergency operation, routine or non-routine maintenance operation, or other planned event.

11.3. Report in accordance with Condition 70 if any of the limits in Condition 11 are exceeded.

[Condition 7.1, Minor Permit No. AQ0417MSS05, April 26, 2013]
[18 AAC 50.040(j) & 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3) & (c)(6)]

12. Air Quality Boundary. Establish and maintain the ambient boundaries used in the ambient impact analysis using the following procedures:

12.1. Comply with the May 10, 2005 “CPF Pad Badami Unit – Public Access Control Plan” (Plan), or a subsequent written version approved by the Department that contains at least the following elements:

a. a topographic map (or maps) that clearly shows the ambient boundaries, water bodies and Central Process Facility (CPF) pad;

b. ambient boundaries that are consistent with the land owner’s authorization to preclude public access from the area within the boundaries;

c. defined methods of establishing and maintaining the boundary; and

d. the date of the revised Public Access Control Plan.

12.2. Do not revise the ambient air boundaries without Department approval. If requested by the Department, submit a revised ambient air impact analysis that demonstrates the emission activities will not cause or contribute to ambient air violations when using the proposed boundary.

12.3. Submit all proposed revisions of the Public Access Control Plan, including the ambient boundary, to the Department's Juneau and Fairbanks Offices. Do not implement any change without written Department approval.

[Condition 7.2, Minor Permit No. AQ0417MSS05, April 26, 2013]
[18 AAC 50.040(j) & 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3) & (c)(6)]

13. Fuel Gas and Produced Gas Sulfur Limit. Operate EU IDs 1, 8, 500, 501, 503, and 505 using fuel gas with a H_2S content not to exceed 250 ppmv and operate EU ID 507 using fuel gas and produced gas with a H_2S content not to exceed 250 ppmv.

13.1. Monitor, record, and report in accordance with Conditions 10.6 through 10.8.

13.2. Report in accordance with Condition 70 if the fuel H_2S content limit in Condition 13 is exceeded.

[Condition 8, Minor Permit No. AQ0417MSS05, April 26, 2013]
[18 AAC 50.040(j) & 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3) & (c)(6)]

14. Diesel Fuel Sulfur Limit. [10] Operate EU IDs 1, 8, 420a, and 421a using distillate fuel oil with a fuel sulfur content not to exceed 0.15 percent by weight (wt% S).

14.1. Monitor, record, and report in accordance with Conditions 10.1 through 10.4.

14.2. Report in accordance with Condition 70 if the fuel sulfur content limit in Condition 14 is exceeded.

[Condition 9, Minor Permit No. AQ0417MSS05, April 26, 2013]
[18 AAC 50.040(j) & 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3) & (c)(6)]

15. Liquid Fuel Consumption Limit, EU IDs 420a and 421a. For EU IDs 420a and 421a, the Permittee shall burn a combined total of no more than 800,000 gallons of liquid fuel during any 12 consecutive-month period.

15.1. Install and operate a dedicated fuel meter accurate to less than five percent error for EU ID 420a and 421a combined; and install and operate a dedicated continuous engine hour monitoring system for each unit.

15.2. Monitor and record the monthly fuel consumption for EU IDs 420a and 421a combined, and the monthly hours of operation for each unit.

[10] This permit does not impose fuel sulfur restrictions on intermittently used oil field support equipment (IUOSE). The Department has instead established off-permit fuel sulfur targets for these units in Policy and Procedure Number 04.02.105 (effective 11/20/06).

15.3. Except as provided in Condition 15.4, calculate and record the 12 consecutive month combined fuel consumption using fuel meter data.

15.4. If the fuel meter for EU IDs 420a and 421a is out of service, estimate the gallons of fuel consumed for the emissions units using the hours of operation recorded in Condition 15.2, assuming the 100 percent load fuel consumption rate in gallons per hour for the unit for any period during which the unit was operating. The fuel consumption rate shall be the design fuel consumption of 97.8 gallons per hour.

15.5. Report in the operating report required by Condition 71:

a. the monthly and 12 consecutive month total fuel consumption for EU IDs 420a and 421a combined; and

b. if the hours of operation were used to calculate the fuel use for any part of the 12 month rolling period as described in Condition 15.4, report the monthly and 12-consecutive month hours of operation for EU IDs 420a and 421a.

15.6. Report in accordance with Condition 70 if the limit in Condition 15 is exceeded.

[Condition 10, Minor Permit No. AQ0417MSS05, April 26, 2013]
[18 AAC 50.040(j) & 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3) & (c)(6)]

16. Fuel Consumption Limits, EU IDs 1 and 8 (Drill Rig). In all drill rig emissions units, EU IDs 1 and 8 listed in Table A, the Permittee shall burn a combined total of no more than 9,000 gallons of liquid fuel per day and 950,000 gallons of liquid fuel during any 12 consecutive-month period.

16.1. Monitor and record for each operational day, the quantity of fuel combusted in all drill rig emissions units, combined. Monitor fuel gas consumption using non-resettable fuel flow meters.

16.2. Calculate and record the daily combined, and 12 consecutive month combined, total fuel consumption in gallons. For units that are fired with fuel gas, convert the quantity of fuel gas burned (in standard cubic feet (scf)) into a diesel gallon equivalent using the conversion factor of 115 scf of fuel gas to one gallon diesel fuel.

16.3. Report in the operating report required by Condition 71, the maximum daily fuel consumption and the 12 consecutive-month total fuel consumption in gallons for all drill rig emissions units combined, for each month of the reporting period.

16.4. Report as a permit deviation, in accordance with Condition 70 any time the fuel consumption exceeds a limit specified in Condition 16.

[Condition 4, Minor Permit No. AQ0417MSS07 Rev. 1, July 8, 2015]
[18 AAC 50.040(j) & 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3) & (c)(6]

Best Available Control Technology (BACT) Limits

17. BACT Controls and Limits. The Permittee shall install emission or operational controls as BACT for the following equipment:

17.1. NOx BACT for fuel burning equipment at Badami Development Facility is no post-combustion emission control with good operational practices. The Permittee shall:

a. Install and operate as BACT for the following fuel burning equipment at Badami Development Facility:

(i) EU ID 420a and EU ID 421a with a modular common rail system (MCRS) as incorporated by the manufacturer;

(ii) EU IDs 500 and 501 with dry low NOx combustion technology (SoLoNOx);

(iii) EU ID 503 with low NOx burners/flue gas recirculation; and

(iv) EU ID 505 with conventional burner technology.

b. Comply with the following NOx emission limits:

(i) EU IDs 500 and 501 shall not exceed 28.4 lb NOx/hr for operation under all conditions, and shall not exceed 85 ppmv corrected to 15 percent oxygen in SoLoNOx mode and at ambient temperatures above 0°F;

(ii) EU ID 503 shall not exceed 0.095 lb NOx/MMBtu; and

(iii) EU ID 505 shall not exceed 0.08 lb NOx/MMBtu.

17.2. CO BACT for fuel burning equipment at Badami Development Facility is no post-combustion emission control with good operational practices. The Permittee shall:

a. Comply with the following CO emission limits as representative of BACT:

(i) EU IDs 500 and 501 shall not exceed 50 ppmv corrected to 15 percent oxygen when operating at 100 percent load in SoLoNOx mode at ambient temperatures above 0°F, 14 lb/hr when operating in SoLoNOx mode and at ambient temperatures above 0°F, and 385 lb/hr for operation under all other conditions;

(ii) EU ID 503 shall not exceed 3.4 lb CO/hr; and

(iii) EU ID 505 shall not exceed 0.15 lb CO/MMBtu.

b. Limit CO emissions from EU IDs 500 and 501, combined, to no greater than 336 tons per 12 consecutive-month period.

17.3. SO_2 BACT for fuel burning equipment is use of low sulfur fuel with no post-combustion controls. The Permittee shall:

a. Comply with the following fuel sulfur limits as representative of BACT:

(i) H_2S content of fuel gas and produced gas fuel shall not exceed 250 ppmv; and

(ii) Sulfur content of fuel oil shall not exceed 0.15 wt% S.

17.4. VOC BACT for fuel burning equipment and fuel storage tanks, and water treatment processes is no controls with good operation practices. BACT for water injection tanks and slop tank is a sealed system design. The flare BACT determination is smokeless tip design. No emission limits are imposed as representing BACT.

17.5. PM-10 BACT for fuel burning equipment is no controls with good operation practices. The Permittee shall:

a. Comply with the following opacity limits as representative of BACT surrogate PM-10 emission limits:

(i) Visible emissions from EU IDs 420a and 421a shall not exceed 20 percent opacity averaged over any six consecutive minutes, except as described in Condition 17.5.a(ii); and

(ii) If both oil and gas production cease for 30 consecutive days, EU IDs 420a and 421a shall not exceed 10 percent opacity averaged over any six consecutive minutes, until oil and gas production resumes.

(iii) Visible emissions from EU IDs 500 and 501 shall not exceed 10 percent opacity averaged over any six consecutive minutes.

(iv) All other industrial processes, incinerators, and fuel burning equipment shall comply with the applicable State visible emission standards listed in Conditions 1 and 21.1

[Condition 12.1a & 12.1c-12.1f, Minor Permit No. AQ0417MSS05, April 26, 2013]
[Condition 2, Minor Permit No. AQ0417MSS06, April 27, 2015]
[18 AAC 50.040(j) & 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3]

18. BACT Monitoring, Recordkeeping, and Reporting. The Permittee shall monitor, record, and reports as follows:

18.1. NOx and CO – To demonstrate compliance with the short-term NOx and CO BACT limits specified in Conditions 17.1.b and 17.2.a, the Permittee shall conduct source testing on EU IDs 500, 501, and 503, in accordance with Section 6 and as follows:

a. For EU IDs 500 and 501:

(i) Conduct source tests during the summer months (April through September) and during winter months (October through March).

(ii) During this permit term, the first summer test on EU IDs 500 and 501 shall be done within 12 months of the effective date of this permit and the second test (winter) during the life of this permit, except as follows:

(A) If results of the previous winter source tests conducted in October 2014 shows that the winter test results are higher than the summer source test results conducted under this permit in all test runs at similar operating loads, the Permittee may elect to conduct source tests on EU IDs 500 or 501 once every five years during winter months only.

(iii) For NOx, conduct source testing at the highest typical operating load of the unit. For units of the same make, model, and design, one unit within the group can be tested. The source test report shall provide NOx emissions (average of three valid one-hour-run results) in ppmv and in lb/hr for each unit tested. At the Permittee's discretion, the NOx BACT source test in this sub-condition may be conducted in conjunction with NSPS Subpart GG NOx source test required under Condition 32.2.a.

(iv) For CO, conduct source testing at no less than four loads representative of the turbine's typical operating range. For units of the same make, model, and design, one unit within the group can be tested. The source test report shall provide CO emissions (average of three valid one-hour-test run results) in ppmv and in lb/hr for each unit tested.

b. For EU ID 503, conduct NOx and CO emission source tests as follows:

(i) once within five years from the most recent source test conducted on the unit;

(ii) at the highest typical operating load of the unit; and

(iii) provide in the source test report NOx and CO emissions results in lb/MMBtu (average of three valid one-hour-run results).

[18 AAC 50.040(j) & 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3) & (c)(6)]

18.2. CO – For EU IDs 500 and 501, monitor, record and report, as follows:

a. Using the existing computer-based control system[11], monitor and record:

(i) operating time in hours (record time in minutes or decimal portions of an hour);

(ii) for each hour, the average percentage natural gas producer (% NGP) speed (use six-minute intervals to calculate the average % NGP speed for each hour of operation); and

(iii) for each hour, time in and out of SoLoNOx operation for each unit.

[11] For any time the computer based system is out of order, the Permittee shall estimate and record the hourly operating time, % NGP speed, and time in and out of SoLoNOx operation for each unit.

b. Calculate and record the hourly CO emissions for EU IDs 500 and 501. Use the SoLoNOx mode and the hourly average percentage NGP speed (as determined in Condition 18.2.a(ii) to determine the appropriate CO emission factors listed in Table B or alternate CO emission factors approved in writing by the Department. Multiply the appropriate CO emission factor by the associated hours of operation to get hourly CO emissions.

c. On calendar month basis, calculate and record the total monthly and 12 consecutive-month period CO emissions for EU IDs 500 and 501 individually, and EU ID 500 and 501 combined.

d. Report in the operating report required by Condition 71, the monthly and 12 consecutive-month total CO emissions for EU IDs 500 and 501, each, and the combined total.

Table B – EU ID 500 and 501 Turbine CO Emission Factors

Emissions unit ID(s)	SoLoNOx Mode	Gas Turbine Load Condition (% NGP speed average hourly value)	CO Emission Factor
500 & 501	In SoLoNOx Mode		4.7 lb/hr
	Out of SoLoNOx Mode	% NGP ≥ 94	4.7 lb/hr
		% NGP ≥ 90 and < 94	202.0 lb/hr
		% NGP ≥ 87 and < 90	236.0 lb/hr
		% NGP ≥ 84 and < 87	261.9 lb/hr
		% NGP < 84	385 lb/hr

18.3. SO_2 – Conduct fuel sulfur monitoring, recordkeeping and reporting in Conditions 10.1 through 10.8 to ensure compliance with SO_2 BACT limits in Condition 17.3.

18.4. PM – Conduct visible emission monitoring as follows:

a. For EU IDs 420a and 421a, continue to conduct Method 9 visible emissions observations using monitoring, recordkeeping and reporting procedures detailed in Conditions 2 through 4. Indicate on the Visible Emissions Observation Form in Section 11 if the unit observed is subject to the 10 percent opacity limit as surrogate PM-10 BACT limit described in Condition 17.5.a(ii).

b. For EU IDs 500 and 501, comply with Condition 1.3.

18.5. Report in accordance with Condition 70 if any of the BACT limits under Condition 17 are exceeded.

[Conditions 12.2 and 12.3, Minor Permit No. AQ0417MSS05, April 26, 2013]
[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 71.6(a)(3) & c(6)]

Restart Project

19. Limits on Use of Load Banks. Except as provided in Condition 20, after February 1, 2013, the Permittee shall not use load banks, water brakes, pump flow controls or other loads that have the single purpose to destroy energy in order to improve the CO emission performance of EU IDs 500 and 501. For purposes of this permit, a load bank is a resistance device that performs no process or space heating function.

[Condition 13, Minor Permit No. AQ0417MSS05, April 26, 2013]
[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 71.6(a)]

20. Load Bank Exception. The Permittee may use a load bank on a short term basis to address intermittent power fluctuations that may occur as a result of bringing on a second turbine for project ramp-up, with the plan of operating both turbines simultaneously. Monitor, record, and report, as follows:

20.1. Record each change in the load bank power use in kW in a written log, noting date, time, and "before" and "after" settings of load bank power use:

a. at each instance the load is adjusted; and

b. twice daily coincident with physical inspections of the load bank, whenever load bank is receiving power.

20.2. Report in the operating report required by Condition 71:

a. the number of hours the load bank was used; and

b. a statement whether the load bank was used to address intermittent power fluctuations as a result of bringing on a second turbine for project ramp-up.

20.3. Report in accordance with Condition 70 if load banks were used for purposes other than to address intermittent power fluctuations, as a result of bringing on a second turbine for project ramp-up as specified in Condition 20.

[Condition 14, Minor Permit No. AQ0417MSS05, April 26, 2013]
[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 71.6(a)]

Insignificant Emissions Units

21. For emissions units at the stationary source that are insignificant as defined in 18 AAC 50.326(d)-(i) that are not listed in this permit, the following apply:

21.1. **Visible Emissions Standard**: The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from an industrial process, fuel-burning equipment, or an incinerator to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.

[18 AAC 50.050(a) & 50.055(a)(1)]

21.2. **Particulate Matter Standard**: The Permittee shall not cause or allow PM emitted from an industrial process or fuel-burning equipment to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.

[18 AAC 50.055(b)(1)]

21.3. **Sulfur Standard**: The Permittee shall not cause or allow sulfur compound emissions, expressed as SO_2, from an industrial process or fuel-burning equipment, to exceed 500 ppm averaged over three hours.

[18 AAC 50.055(c)]

21.4. **General MR&R for Insignificant Emissions units**

a. The Permittee shall submit the certification of compliance of Condition 72 based on reasonable inquiry;

b. The Permittee shall comply with the requirements of Condition 53;

c. The Permittee shall report in the operating report required by Condition 71 if an emissions unit is insignificant because of actual emissions less than the thresholds of 18 AAC 50.326(e) and actual emissions become greater than any of those thresholds; and

d. No other monitoring, recordkeeping or reporting is required.

[18 AAC 50.346(b)(4)]

Section 4. Federal Requirements

Emissions units Subject to Federal NSPS Subpart A

22. NSPS Subpart A Notification. For any affected facility[12] or existing facility[13] regulated under NSPS requirements in 40 C.F.R. 60, the Permittee shall furnish the Department and EPA written or electronic notification of:

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.7 & 60.15]

22.1. the date that construction or reconstruction of an affected facility commences postmarked no later than 30 days after such date;

[40 C.F.R. 60.7(a)(1), Subpart A]

22.2. the actual date of initial startup of an affected facility postmarked within 15 days after such date;

[40 C.F.R. 60.7(a)(3), Subpart A]

22.3. any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies unless that change is specifically exempted under an applicable subpart or in 40 C.F.R. 60.14(e), postmarked 60 days or as soon as practicable before the change is commenced and shall include:

a. information describing the precise nature of the change,

b. present and proposed emission control systems,

c. productive capacity of the facility before and after the change, and

d. the expected completion date of the change;

[40 C.F.R. 60.7(a)(4), Subpart A]

22.4. any proposed replacement of an existing facility, for which the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, postmarked as soon as practicable, but no less than 60 days before commencement of replacement, and including the following information: [14]

a. the name and address of owner or operator,

b. the location of the existing facility,

[12] *Affected facility* means, with reference to a stationary source, any apparatus to which a standard applies, as defined in 40 C.F.R. 60.2, effective 7/1/07.

[13] *Existing facility* means, with reference to a stationary source, any apparatus of the type for which a standard is promulgated in this part, and the construction or modification of which was commenced before the date of proposal of that standard; or any apparatus which could be altered in such a way as to be of that type, as defined in 40 C.F.R. 60.2, effective 7/1/07.

[14] The Department and EPA may request additional relevant information subsequent to this notice.

c. a brief description of the existing facility and the components that are to be replaced,

d. a description of the existing and proposed air pollution control equipment,

e. an estimate of the fixed capital cost of the replacements, and of constructing a comparable entirely new facility,

f. the estimated life of the existing facility after the replacements, and

g. a discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

[40 C.F.R. 60.15(d)]

23. NSPS Subpart A Startup, Shutdown, & Malfunction Requirements. The Permittee shall maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of EU IDs 500, 501, and 503, any malfunctions of associated air-pollution control equipment, or any periods during which a continuous monitoring system or monitoring device for EU IDs 500, 501, and 503 is inoperative.

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.7(b), Subpart A]

24. NSPS Subpart A Excess Emissions and Monitoring Systems Performance Report. The Permittee shall submit to the Department and to EPA a written "excess emissions and monitoring systems performance report " (EEMSP)[15, 16] any time a limit in Conditions 31 and 33 has been exceeded as described in this condition. Submit the EEMSP reports with the summary report form as required in Condition 25. Written reports of excess emissions shall include the following information:

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.7(c), Subpart A]

24.1. The magnitude of excess emissions, any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the process operating time during the reporting period.

[40 C.F.R. 60.7(c)(1), Subpart A]

24.2. Identification of each period of excess emissions that occurred during startup, shutdown, and malfunction of EU IDs 500 and 501; the nature and cause of any malfunction, and the corrective action taken or preventative measures adopted.

[40 C.F.R. 60.7(c)(2), Subpart A]

24.3. The date and time identifying each period during which a Continuous Monitoring System (CMS) was inoperative except for zero and span checks and the nature of any repairs or adjustments.

[40 C.F.R. 60.7(c)(3), Subpart A]

[15] The Federal EEMSP report is not the same as the State excess emission report required by Condition 70.

[16] Periods of excess emissions and monitor downtime for units subject to the NSPS Subpart GG SO_2 limit (EU IDs 500 and 501) are defined in 40 C.F.R. 60.334(j)(2).

24.4. A statement indicating whether or not any excess emissions occurred or the CMS was inoperative, repaired, or adjusted, at any time during the reporting period.

[40 C.F.R. 60.7(c)(4), Subpart A]

25. NSPS Subpart A Summary Report Form. The Permittee shall submit to the Department and to EPA one "summary report form" in the format shown in Figure 1 of 40 C.F.R. 60.7 (see Attachment A) for each pollutant monitored for EU IDs 500 and 501. Except as provided in Condition 34.4.b, or when more frequent reporting is specifically required by an applicable subpart, case-by-case basis, or the EPA, the report shall be submitted semiannually, postmarked by the 30th day following the end of each 6-month period:

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.7(c) & (d), Subpart A]

25.1. If the total duration of excess emissions for the reporting period is less than one percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than five percent of the total operating time for the reporting period, submit a summary report form **unless** the EEMSP report described in Condition 24 is requested, or

[40 C.F.R. 60.7(d)(1), Subpart A]

25.2. If the total duration of excess emissions for the reporting period is one percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is five percent or greater of the total time for the reporting period, then submit a summary report form **and the EEMSP** described in Condition 24.

[40 C.F.R. 60.7(d)(2), Subpart A]

26. NSPS Subpart A Performance (Source) Tests. The Permittee shall conduct source tests according to the applicable requirements of 40 C.F.R. 60.8 and Section 6 on any affected facility at such times as may be required by EPA, and shall provide the Department and EPA with a written report of the results of the source test.

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.8(a), Subpart A]

27. NSPS Subpart A Good Air Pollution Control Practice. At all times, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate EU IDs 500, 501, and 503 including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. The Administrator will determine whether acceptable operating and maintenance procedures are being used based on information available to the Administrator, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance records, and inspections of EU IDs 500, 501, and 503.

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.11(d), Subpart A]

28. NSPS Subpart A Credible Evidence. For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of the standards set forth in Conditions 31 and 33, nothing in 40 C.F.R. Part 60 shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether EU IDs 500 and 501 would have been in compliance with applicable requirements of 40 C.F.R. Part 60 if the appropriate performance or compliance test or procedure had been performed.

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.11(g), Subpart A]

29. NSPS Subpart A Concealment of Emissions. The Permittee shall not build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of a standard set forth in Conditions 31, 33, and 36.1. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard that is based on the concentration of a pollutant in the gases discharged to the atmosphere.

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.12, Subpart A]

Steam Generating Units Subject to NSPS Subpart Dc, EU ID 503

30. NSPS Subpart Dc Fuel Consumption. For EU ID 503 listed in Table A, the Permittee shall record the amount of each fuel combusted during each operating month and maintain the records for a period of two years following the date of such record; or monitor according to an EPA approved custom fuel-monitoring schedule. The Permittee shall determine fuel consumption in EU ID 503, as follows:

[18 AAC 50.040(a)(2)(D)]
[40 C.F.R. 60.48c(g)(2) and 60.48c(i), Subpart Dc]

30.1. Unless otherwise approved, the Permittee shall maintain a record of the amount of fuel combusted on a quarterly basis for EU ID 503.

[Alternative Monitoring Plan, 1/28/99]

Turbines Subject to NSPS Subpart GG, EU IDs 500 and 501

31. NSPS Subpart GG NOx Standard. The Permittee shall not allow the exhaust gas concentration of NOx to exceed 191 ppmvd at 15 percent O_2, ISO, dry exhaust basis from each of EU IDs 500 and 501 listed in Table A.

[18 AAC 50.040(a)(2)(V)]
[40 C.F.R. 60.332(a)(2) & (d), Subpart GG]

32. NO_X MR&R Requirements. The Permittee shall monitor, record, and report compliance with the Subpart GG NO_X standard in Condition 31, as follows:

32.1. **Emergency Fuel**. Stationary gas turbines with a heat input greater than or equal to 10.7 gigajoules per hour (10 million Btu/hour) when fired with natural gas are exempt from the standard in Condition 31 when being fired with an emergency fuel. Each period during which an exemption is in effect shall be included in the report required in Condition 24. For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported.

32.2. **Monitoring.** The Permittee shall comply with the following:

[18 AAC 50.040(j); 18 AAC 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3)(i) & (c)(6)]

a. **Periodic Testing.** For each turbine subject to Condition 31 that operates for 400 hours or more in any 12-month period during the life of this permit, the Permittee shall satisfy either Condition 32.2.a(i) or Condition 32.2.a(ii).

(i) For existing turbines whose latest emissions source testing was certified as operating at less than or equal to 90 percent of the limit shown in Condition 31, the Permittee shall conduct a NOx and O_2 source test under 40 C.F.R. 60, Appendix A, Method 20, or Method 7E and either Method 3 or 3A within the first applicable criteria below:

(A) Within 5 years of the latest performance test, or

(B) Within 1 year of the effective date of this permit if the last source test occurred greater than five years prior to the effective date of this permit and the 400-hour threshold was triggered within 6 months of the permit issue date, or

(C) Within 1 year after exceeding 400 hours of operation in a 12-month period if the last source test occurred greater than 4 years prior to the exceedance.

(ii) For existing turbines whose latest emissions source testing was certified as operating at greater than 90 percent of the limit shown in Condition 31, the Permittee shall conduct a NOx and O_2 source test under 40 C.F.R. 60, Appendix A-7, Method 20, or Method 7E and either Method 3 or 3A, annually until two consecutive tests show performance results certified at less than or equal to 90 percent of the limit of Condition 31.

b. **Substituting Test Data.** The Permittee may use a Method 20, or Method 7E and either Method 3 or 3A test under Condition 32.2.a performed on only one of a group of similarly configured turbines to satisfy the requirements of those conditions for the other turbines in the group if:

(i) The Permittee demonstrates that test results are less than or equal to 90 percent of the applicable emission limits of Condition 31, and are projected under Condition 32.2.c to be less than or equal to 90 percent of the applicable limit at maximum load; and

(ii) For any source test conducted after the effective date of this permit, the Permittee identifies in a source test plan under Condition 62:

(A) the turbine to be tested;

(B) the other turbines in the group that are to be represented by the test; and

(C) why the turbine to be tested is representative, including that each turbine in the group

(1) is located at a stationary source operated and maintained by the Permittee;

(2) operates under close to identical ambient conditions as the untested turbines;

(3) is the same make and model and has identical injectors and combustor;

(4) uses the same fuel type from the same supply origin.

(iii) The Permittee may not use substitute test results to represent emissions from a turbine or group of turbines if that turbine or group of turbines is operating at greater than 90 percent of the applicable emission limits of Condition 31.

c. **Load.** The Permittee shall comply with the following:

(i) Conduct all tests under Condition 32.2 in accordance with 40 C.F.R. 60.335(b)(2), except as otherwise approved in writing by the Department, or by EPA if the circumstances at the time of the EPA approval are still valid. For the highest load condition, if it is not possible to operate the turbine during the test at maximum load, the Permittee will test the turbine when operating at the highest load achievable by the turbine under the ambient and stationary source operating conditions in effect at the time of the test.

(ii) Demonstrate in the source test plan for any test performed after the effective date of this permit whether the test is scheduled when maximum NOx emissions are expected.

(iii) If the highest operating rate tested is less than the maximum load of the tested turbine or another turbine represented by the test data,

(A) for each such turbine the Permittee shall provide to the Department as an attachment to the source test report

(1) additional test information from the manufacturer or from previous testing of units in the group of turbines; if using previous testing of the group of turbines, the information must include all available test data for the turbines in the group, and

(2) a demonstration based on the additional test information that projects the test results from Condition 32 to predict the highest load at which emissions will comply with the limit in Condition 31;

(B) the Permittee shall not operate any turbine represented by the test data at loads for which the Permittee's demonstration predicts that emissions will exceed the emission limit of Condition 31;

(C) the Permittee shall comply with a written finding prepared by the Department that

(1) the information is inadequate for the Department to reasonably conclude that compliance is assured at any load greater than the test load, and that the Permittee must not exceed the test load;

(2) the highest load at which the information is adequate for the Department to reasonably conclude that compliance assured is less than maximum load, and the Permittee must not exceed the highest load at which compliance is predicted, or

(3) the Permittee must retest during a period of greater expected demand on the turbine; and

(D) the Permittee may revise a load limit by submitting results of a more recent Method 20, or Method 7E and either Method 3 or 3A test done at a higher load, and, if necessary, the accompanying information and demonstration described in Condition 32.2.c(iii)(A); the new limit is subject to any new Department finding under Condition 32.2.c(iii)(C).

(iv) In order to perform an emission test required by Conditions 32.2.a and 32.2.b, the Permittee may operate a turbine at a higher load than that prescribed by Condition 32.2.c(iii).

(v) For the purposes of Conditions 32 through 32.4, maximum load means the hourly average load that is the smallest of

(A) 100 percent of manufacturer's design capacity of the gas turbine at ISO standard day conditions;

(B) the highest load allowed by an enforceable condition that applies to the turbine; or

(C) the highest load possible considering permanent physical restraints on the turbine or the equipment which it powers.

32.3. **Recordkeeping.** The Permittee shall keep records as follows:

[18 AAC 50.040(j); 18 AAC 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3)(ii) & (c)(6)]

a. The Permittee shall comply with the following for each turbine for which a demonstration under Condition 32.2.c(iii) does not show compliance with the emission limit of Condition 31 at maximum load.

(i) The Permittee shall keep records of

(A) load; or

(B) as approved by the Department, surrogate measurements for load and the method for calculating load from those measurements.

(ii) Records in Condition 32.3.a shall be hourly or otherwise as approved by the Department.

(iii) Within one month after submitting a demonstration under Condition 32.2.c(iii)(A)(2) that predicts that the highest load at which emissions will comply is less than maximum load, or within one month of a Department finding under Condition 32.2.c(iii)(C), whichever is earlier, the Permittee shall propose to the Department how they will measure load or load surrogates, and shall propose and comply with a schedule for installing any necessary equipment and beginning monitoring. The Permittee shall comply with any subsequent Department direction on the load monitoring methods, equipment, or schedule.

b. For any turbine subject to Condition 31 that will operate less than 400 hours in any 12 consecutive months, the Permittee shall keep monthly records of the hours of operation.

32.4. **Reporting.** The Permittee shall report as follows:

[18 AAC 50.040(j); 18 AAC 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3)(iii) & (c)(6)]

a. In each operating report under Condition 71, the Permittee shall list for each turbine tested or represented by testing at less than maximum load and for which the Permittee must limit load under Condition 32.2.c(iii)

(i) the load limit;

(ii) the turbine identification; and

(iii) the highest load recorded under Condition 32.3.a during the period covered by the operating report.

b. In each operating report under Condition 71 for each turbine for which Condition 32 has not been satisfied because the turbine normally operates less than 400 hours in any 12 consecutive months, the Permittee shall identify

(i) the turbine;

(ii) the highest number of operating hours for any 12 consecutive months ending during the period covered by the report; and

(iii) any turbine that operated for 400 or more hours.

c. The Permittee shall report under Condition 70 if

(i) a test result exceeds the emission standard;

(ii) Method 20, or Method 7E and either Method 3 or 3A testing is required under Condition 32.2.a(i) or 32.2.a(ii) but not performed, or

(iii) the turbine was operated at a load exceeding that allowed by Conditions 32.2.c(iii)(B) and 32.2.c(iii)(C); exceeding a load limit is deemed a single violation rather than a multiple violation of both monitoring and the underlying emission limit.

[18 AAC 50.220(a) - (c); 18 AAC 50.040(a)(1)]
[40 C.F.R. 60.8(b), Subpart A]

33. NSPS Subpart GG SO_2 Standard. The Permittee shall not allow the sulfur content for the fuel burned in EU IDs 500 and 501 listed in Table A to exceed 0.8 percent by weight.

[18 AAC 50.040(a)(2)(V)]
[40 C.F.R. 60.333(b), Subpart GG]

34. SO_2 MR&R Requirements. The Permittee shall monitor, record, and report compliance with the Subpart GG SO_2 standard in Condition 33, as follows:

34.1. **Monitoring.** The Permittee shall monitor compliance with the standard listed in this condition as follows:

[18 AAC 50.040(a)(2)(V)]
[40 C.F.R. 60.334 & 60.335, Subpart GG]

a. Monitor the total sulfur content of the fuel being fired in the turbine, except as provided in Conditions 34.1.b. The sulfur content of the fuel must be determined using total sulfur methods described in Condition 34.2.a. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4,000 ppmw), ASTM D4084–82, 94, D5504–01, D6228–98, or Gas Processors Association Standard 2377–86, which measure the major sulfur compounds may be used.

[40 C.F.R. 60.334(h)(1), Subpart GG]

b. The owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in 40 C.F.R. 60.331(u), regardless of whether an existing custom schedule approved by the Administrator requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data, which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in 40 C.F.R. 75, Appendix D, Section 2.3.1.4 or Section 2.3.2.4 is required.

[40 C.F.R. 60.334(h)(3), Subpart GG]

c. For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the Permittee may, without submitting a special petition to the Administrator, continue monitoring on this schedule.[17]

[40 C.F.R. 60.334(h)(4), Subpart GG]

d. The frequency of determining the sulfur content of the fuel shall be as follows:

(i) **Gaseous fuel.** If the Permittee elects not to demonstrate sulfur content using options in Condition 34.1.b, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined under Condition 34.1.a and recorded once per unit operating day.

[40 C.F.R. 60.334(i)(2), Subpart GG]

(ii) **Custom Schedules.** Notwithstanding the requirements of Condition 34.1.d(i):

(A) The Permittee may develop a custom schedule for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply, according to the provisions and as allowed under 40 C.F.R. 60.334(i)(3). The two custom sulfur monitoring schedules set forth in 40 C.F.R. 60.334(i)(3)(i)(A) through (D) and 60.334(i)(3)(ii) are acceptable without prior Administrative approval.

40 C.F.R. 60.334(i)(3), Subpart GG

[17] Alternative Monitoring Plan approved by the EPA on November 12, 1998.

(B) Alternatively, as provided under Condition 34c, the Permittee may continue to use the Alternative Monitoring Plan approved by EPA on 11/12/98. The EPA-approved AMP (11/12/98) requires quarterly monitoring for six calendar quarters, then reduces monitoring to semiannually if H_2S results are below 80 ppm.

[Alternative Monitoring Plan, 11/12/98]

34.2. **Test Methods and Procedures.** If the Permittee periodically determines the sulfur content of the fuel combusted in the turbine under Condition 34.1.d(ii) a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

[18 AAC 50.040(a)(2)(V)]
[40 C.F.R. 60.335(b)(10), Subpart GG]

a. For gaseous fuels, ASTM D1072-80, 90; D3246-81, 92, 96; D4468-85; or D6667-01. The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

[40 C.F.R. 60.335(b)(10)(ii), Subpart GG]

b. The fuel analyses required under Condition 34.2 may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

[40 C.F.R. 60.335(b)(11), Subpart GG]

34.3. **Recordkeeping.** The Permittee shall keep records as required by Condition 66 and the EPA-approved AMP (11/12/98) as follows:

a. Maintain records of all sulfur monitoring data.

b. Maintain a record documenting the source of fuel gas. A substantial change in fuel gas quality shall be considered a change in fuel supply.

c. Maintain records of all turbine operation on all fuels other than fuel gas.

d. Maintain records on-site for a period of five years from the generation of such record.

[18 AAC 50.040(j); 18 AAC 50.326(j)]
[40 C.F.R. 71.6(a)(3)(ii)]
[Alternative Monitoring Plan, 11/12/98]

34.4. **Reporting.** The Permittee shall report as follows:

a. For each affected unit that periodically determines the fuel sulfur content under Condition 34, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with 40 C.F.R. 60.7(c) as summarized in Condition 24 except where otherwise approved by a custom fuel monitoring schedule. Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction as described by 40 C.F.R. 60.334(j)(2).

b. As required by the EPA-approved AMP (11/12/98), submit to EPA within 60 days of any changes in supplier or source of fuel, or use of any fuel other than fuel gas.

c. As required by the EPA-approved AMP (11/12/98), annually report the results of all sulfur monitoring to EPA. Provide a copy of the report to the Department by February 1 following the end of each calendar year.

[Alternative Monitoring Plan, 11/12/98]
[18 AAC 50.040(j); 18 AAC 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3)(iii) & (c)(6)]

Compression Ignition (CI) Internal Combustion Engine (ICE) Subject to NSPS Subpart IIII, EU IDs 420a and 421a[18]

35. NSPS Subpart IIII Applicability and General Compliance Requirements. For EU IDs 420a and 421a listed in Table A, the Permittee shall comply with the applicable requirements for a non-emergency stationary compression ignition (CI) internal combustion engine (ICE) whose construction[19], modification[20], or reconstruction[21] commences after July 11, 2005 where the stationary CI ICE is manufactured after April 1, 2006.

[18 AAC 50.040(a)(2)(OO) & (j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]
[40 C.F.R. 60.4200(a)(2)(i), Subpart IIII]

35.1. Operate and maintain the stationary CI ICE and control device according to the manufacturer's written instructions or procedures developed by the Permittee that are approved by the engine manufacturer over the entire life of the engine. In addition, the Permittee may only change those settings that are permitted by the manufacturer.

[40 C.F.R. 60.4206 & 60.4211(a), Subpart IIII]

[18] The provisions of NSPS Subpart IIII listed in Conditions 35 through 38 are current as of January 30, 2013. Should EPA promulgate revisions to this subpart, the Permittee shall be subject to the revised final provisions as promulgated and not the superseded provisions summarized in these conditions.

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

[20] As defined in 40 C.F.R. 60.14(a).

[21] As defined in 40 C.F.R. 60.15(b).

35.2. Comply with the applicable provisions of Subpart A as specified in Table 8 to Subpart IIII.

[40 C.F.R. 60.4218 & Table 8, Subpart III]

36. NSPS Subpart IIII Emission Standards. For EU ID 420a and 421a, the Permittee shall comply with the following emission standards:

[18 AAC 50.040(a)(2)(OO) & (j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]

36.1. Exhaust emission from EU IDs 420a and 421a shall not exceed the following applicable exhaust emission standards for new nonroad CI engines in 40 C.F.R. 89.112 and 89.113 for all pollutants, for the same displacement and maximum engine power (i.e., Tier 2 emission factors):

a. 6.4 g/kW-hr for NMHC + NOx;

b. 3.5 g/KW-hr for CO;

c. 0.20 g/kW-hr for PM; and

d. Exhaust opacity from EU IDs 420a and 421a must not exceed:

(i) 20 percent during the acceleration mode;

(ii) 15 percent during the lugging mode; and

(iii) 50 percent during the peaks in either the acceleration or lugging modes.

[40 C.F.R. 60.4216(c), 60.4205(b) & 60.4202(a)(2), Subpart IIII]
[40 C.F.R. 89.112(a) & Table A-1 & 89.113(a), Subpart B, 7/13/05]

37. NSPS Subpart IIII Monitoring and Recordkeeping. For EU IDs 420a and 421a, the Permittee shall comply with the following:

[18 AAC 50.040(a)(2)(OO) & (j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(3)(i) & (ii) and 71.6(c)(6)]

37.1. Demonstrate compliance with the emission standards by purchasing an engine certified to the applicable emission standards in Condition 36.1. The engine must be installed and configured according to the manufacturer's specifications, except as permitted in Condition 37.2.

[40 C.F.R. 60.4209 & 60.4211(c), Subpart IIII]

37.2. If the Permittee does not install, configure, operate, and maintain EU IDs 420a and 421a and control device according to the manufacturer's emission-related written instructions, or changes emission-related settings in a way that is not permitted by the manufacturer, the Permittee shall demonstrate compliance in accordance with 40 C.F.R. 60.4211(g)(3).

[40 C.F.R. 60.4211(g)(3), Subpart IIII]
[40 C.F.R. 60.4209(b) & 60.4214(c), Subpart IIII]

38. NSPS Subpart IIII Reporting. For EU IDs 420a and 421a, the Permittee shall report in accordance with Condition 70 in the event of excess emissions or deviation from any of the requirements of Conditions 35 through 37.

[18 AAC 50.040(j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(3)(iii) & (c)(6)]

General Federal Requirements

39. Asbestos NESHAP. The Permittee shall comply with the applicable requirements set forth in 40 C.F.R. 61.145 and 61.150 of Subpart M, and the applicable sections set forth in 40 C.F.R. 61, Subpart A and Appendix A.

[18 AAC 50.040(b)(1) & (2)(F), & 50.326(j)]
[40 C.F.R. 61, Subparts A & M, and Appendix A]

40. Protection of Stratospheric Ozone, 40 C.F.R. 82.

Subpart F – Recycling and Emissions Reduction

40.1. The Permittee shall comply with the standards for recycling and emission reduction of refrigerants set forth in 40 C.F.R. 82, Subpart F.

[18 AAC 50.040(d) & 50.326(j)]
[40 C.F.R. 82, Subpart F]

Subpart G – Significant New Alternatives Policy (Halon)

40.2. The Permittee shall comply with the applicable prohibitions set out in 40 C.F.R. 82.174(b) – (d) (Protection of Stratospheric Ozone Subpart G – Significant New Alternatives Policy Program).

[18 AAC 50.040(d)]
[40 C.F.R. 82.174 (b) - (d),]

Subpart H – Halon Emission Reduction

40.3. The Permittee shall comply with the applicable prohibitions set out in 40 C.F.R. 82.270(b) – (f) (Protection of Stratospheric Ozone Subpart H – Halon Emission Reduction).

[18 AAC 50.040(d)]
[40 C.F.R. 82.270 (b)-(f)]

NESHAPs Applicability Determinations

41. The Permittee shall determine rule applicability and designation of affected sources under National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Source Categories (40 C.F.R. 63) in accordance with the procedures described in 40 C.F.R. 63.1(b).

41.1. If an owner or operator of a stationary source who is in the relevant source category determines that the source is not subject to a relevant standard or other requirement established under 40 C.F.R. 63, the owner or operator must keep a record as specified in §63.10(b)(3).

41.2. If a source becomes affected by an applicable subpart of 40 C.F.R. 63, the owner or operator shall comply with such standard by the compliance date established by the Administrator in the applicable subpart, in accordance with 40 C.F.R. 63.6(c).

41.3. After the effective date of any relevant standard promulgated by the Administrator under this part, an owner or operator who constructs a new affected source that is not major-emitting or reconstructs an affected source that is not major-emitting that is subject to such standard, or reconstructs a source such that the source becomes an affected source subject to the standard, must notify the Administrator and the Department of the intended construction or reconstruction. The notification must be submitted in accordance with the procedures in 40 C.F.R. 63.9(b).

[18 AAC 50.040(c)(1) & 50.040(j); 18 AAC 50.326(j)]
[40 C.F.R. 71.6(a)(3)(ii)]
[40 C.F.R. 63.1(b), 63.5(b)(4), 63.6(c)(1), 63.9(b), & 63.10(b)(3), Subpart A]

42. NSPS and NESHAP Reports. The Permittee shall:

42.1. **Reports:** Except for federal reports and notices submitted through EPA's Central Data Exchange (CDX) and Compliance and Emissions Data Reporting Interface (CEDRI) online reporting system, attach to the operating report required by Condition 71 for the period covered by the report, a copy of any NSPS and NESHAPs reports submitted to the U.S. Environmental Protection Agency (EPA) Region 10. For reports submitted through CDX/CEDRI, state in the operating report the date and a brief description of each of the online reports submitted during the reporting period; and

42.2. **Waivers**: Upon request by the Department, provide a written copy of any EPA-granted alternative monitoring requirement, custom monitoring schedule or waiver of the federal emission standards, recordkeeping, monitoring, performance testing, or reporting requirements. The Permittee shall keep a copy of each U.S. EPA-issued monitoring waiver or custom monitoring schedule with the permit.

[18 AAC 50.326(j)(4) & 50.040(j)]
[40 C.F.R. 60.13, 63.10(d) & (f), & 40 C.F.R. 71.6(c)(6)]

Section 5. General Conditions

Standard Terms and Conditions

43. Each permit term and condition is independent of the permit as a whole and remains valid regardless of a challenge to any other part of the permit.

[18 AAC 50.326(j)(3), 50.345(a) & (e)]

44. The permit may be modified, reopened, revoked and reissued, or terminated for cause. A request by the Permittee for modification, revocation and re-issuance, or termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

[18 AAC 50.326(j)(3), 50.345(a) & (f)]

45. The permit does not convey any property rights of any sort, nor any exclusive privilege.

[18 AAC 50.326(j)(3), 50.345(a) & (g)]

46. Administration Fees. The Permittee shall pay to the Department all assessed permit administration fees. Administration fee rates are set out in 18 AAC 50.400-403.

[18 AAC 50.326(j)(1), 50.400, & 50.403]
[AS 37.10.052(b), 11/04; AS 46.14.240]

47. Assessable Emissions. The Permittee shall pay to the Department an annual emission fee based on the stationary source's assessable emissions as determined by the Department under 18 AAC 50.410. The Department will assess fees per ton of each air pollutant that the stationary source emits or has the potential to emit in quantities greater than 10 tons per year. The quantity for which fees will be assessed is the lesser of

47.1. the stationary source's assessable potential to emit of 931 TPY; or

47.2. the stationary source's projected annual rate of emissions that will occur from July 1 to the following June 30, based upon credible evidence of actual annual emissions emitted during the most recent calendar year or another 12-month period approved in writing by the Department, when demonstrated by the most representative of one or more of the following methods:

a. an enforceable test method described in 18 AAC 50.220;

b. material balance calculations;

c. emission factors from EPA's publication AP-42, Vol. I, adopted by reference in 18 AAC 50.035; or

d. other methods and calculations approved by the Department including appropriate vendor-provided emissions factors when sufficient documentation is provided.

[18 AAC 50.040(j)(3), 50.035, 50.326(j)(1), 50.346(b)(1), 50.410, & 50.420]
[40 C.F.R. 71.5(c)(3)(ii)]

48. Assessable Emission Estimates. Emission fees will be assessed as follows:

48.1. no later than March 31 of each year, the Permittee may submit an estimate of the stationary source's assessable emissions to ADEC, Air Permits Program, ATTN: Assessable Emissions Estimate, 410 Willoughby Ave., Suite 303, PO Box 111800, Juneau, AK 99811-1800; the submittal must include all of the assumptions and calculations used to estimate the assessable emissions in sufficient detail so the Department can verify the estimates; or

48.2. if no estimate is submitted on or before March 31 of each year, emission fees for the next fiscal year will be based on the potential to emit set forth in Condition 47.1.

[18 AAC 50.040(j)(3), 50.326(j)(1), 50.346(b)(1), 50.410, & 50.420]
[40 C.F.R. 71.5(c)(3)(ii)]

49. Good Air Pollution Control Practice. The Permittee shall do the following for EU IDs 505 and 507:

49.1. perform regular maintenance considering the manufacturer's or the operator's maintenance procedures;

49.2. keep records of any maintenance that would have a significant effect on emissions; the records may be kept in electronic format; and

49.3. keep a copy of either the manufacturer's or the operator's maintenance procedures.

[18 AAC 50.326(j)(3), & 50.346(b)(5)]

50. Dilution. The Permittee shall not dilute emissions with air to comply with this permit. Monitoring shall consist of an annual certification that the Permittee does not dilute emissions to comply with this permit.

[18 AAC 50.045(a)]

51. Reasonable Precautions to Prevent Fugitive Dust. A person who causes or permits bulk materials to be handled, transported, or stored, or who engages in an industrial activity or construction project shall take reasonable precautions to prevent particulate matter from being emitted into the ambient air.

[18 AAC 50.045(d), 50.040(e), 50. 326(j)(3), & 50.346(c)]

52. Stack Injection. The Permittee shall not release materials other than process emissions, products of combustion, or materials introduced to control pollutant emissions from a stack at a stationary source constructed or modified after November 1, 1982, except as authorized by a construction permit, Title V permit, or air quality control permit issued before October 1, 2004.

[18 AAC 50.055(g)]

53. Air Pollution Prohibited. No person may permit any emission which is injurious to human health or welfare, animal or plant life, or property, or which would unreasonably interfere with the enjoyment of life or property.

[18 AAC 50.110, 50.040(e), 50.326(j)(3), & 50.346(a)]
[40 C.F.R. 71.6(a)(3)]

53.1. **Monitoring, Recordkeeping, and Reporting for Condition 53:**

a. If emissions present a potential threat to human health or safety, the Permittee shall report any such emissions according to Condition 70.

b. As soon as practicable after becoming aware of a complaint that is attributable to emissions from the stationary source, the Permittee shall investigate the complaint to identify emissions that the Permittee believes have caused or are causing a violation of Condition 53.

c. The Permittee shall initiate and complete corrective action necessary to eliminate any violation identified by a complaint or investigation as soon as practicable if

(i) after an investigation because of a complaint or other reason, the Permittee believes that emissions from the stationary source have caused or are causing a violation of Condition 53; or

(ii) the Department notifies the Permittee that it has found a violation of Condition 53.

d. The Permittee shall keep records of

(i) the date, time, and nature of all emissions complaints received;

(ii) the name of the person or persons that complained, if known;

(iii) a summary of any investigation, including reasons the Permittee does or does not believe the emissions have caused a violation of Condition 53; and

(iv) any corrective actions taken or planned for complaints attributable to emissions from the stationary source.

e. With each stationary source operating report under Condition 71, the Permittee shall include a brief summary report which must include

(i) the number of complaints received;

(ii) the number of times the Permittee or the Department found corrective action necessary;

(iii) the number of times action was taken on a complaint within 24 hours; and

(iv) the status of corrective actions the Permittee or Department found necessary that were not taken within 24 hours.

f. The Permittee shall notify the Department of a complaint that is attributable to emissions from the stationary source within 24 hours after receiving the complaint, unless the Permittee has initiated corrective action within 24 hours of receiving the complaint.

54. Technology-Based Emission Standard. If an unavoidable emergency, malfunction (as defined in 18 AAC 50.235(d)), or non-routine repair (as defined in 18 AAC 50.990(64), causes emissions in excess of a technology-based emission standard[22] listed in Conditions 17, 31, 33, 36, and 40.1 (refrigerants), the Permittee shall

54.1. take all reasonable steps to minimize levels of emissions that exceed the standard; and

54.2. report in accordance with Condition 70; the report must include information on the steps taken to mitigate emissions and corrective measures taken or to be taken.

[18 AAC 50.235(a), 50.326(j)(4), & 50.040(j)(4)]
[40 C.F.R. 71.6(c)(6)]

Open Burning Requirements

55. Open Burning. If the Permittee conducts open burning at this stationary source, the Permittee shall comply with the requirements of 18 AAC 50.065. The Permittee shall:

55.1. keep written records to demonstrate that the Permittee complies with the limitations in this condition and the requirements of 18 AAC 50.065. Upon request by the Department, submit copies of the records; and

55.2. include this condition in the annual certification required under Condition 72.

[18 AAC 50.065, 50.040(j), & 50.326(j)]
[40 C.F.R. 71.6(a)(3)]

[22] As defined in 18 AAC 50.990(106), the term "*technology-based emission standard*" means a best available control technology (BACT) standard; a lowest achievable emission rate (LAER) standard; a maximum achievable control technology (MACT) standard established under 40 C.F.R. 63, Subpart B, adopted by reference in 18 AAC 50.040(c); a standard adopted by reference in 18 AAC 50.040(a) or (c); and any other similar standard for which the stringency of the standard is based on determinations of what is technologically feasible, considering relevant factors.

Section 6. General Source Testing and Monitoring Requirements.

56. Requested Source Tests. In addition to any source testing explicitly required by the permit, the Permittee shall conduct source testing as requested by the Department to determine compliance with applicable permit requirements.

[18 AAC 50.220(a) & 50.345(a) & (k)]

57. Operating Conditions. Unless otherwise specified by an applicable requirement or test method, the Permittee shall conduct source testing

[18 AAC 50.220(b)]

57.1. at a point or points that characterize the actual discharge into the ambient air; and

57.2. at the maximum rated burning or operating capacity of the emissions unit or another rate determined by the Department to characterize the actual discharge into the ambient air.

58. Reference Test Methods. The Permittee shall use the following test methods when conducting source testing for compliance with this permit:

58.1. Source testing for compliance with requirements adopted by reference in 18 AAC 50.040(a) must be conducted in accordance with the methods and procedures specified in 40 C.F.R. 60.

[18 AAC 50.220(c)(1)(A) & 50.040(a)]
[40 C.F.R. 60]

58.2. Source testing for compliance with requirements adopted by reference in 18 AAC 50.040(c) must be conducted in accordance with the source test methods and procedures specified in 40 C.F.R. 63.

[18 AAC 50.040(c) & 50.220(c)(1)(C)]
[40 C.F.R. 63]

58.3. Source testing for the reduction in visibility through the exhaust effluent must be conducted in accordance with the procedures set out in Reference Method 9. The Permittee may use the form in Section 11 to record data.

[18 AAC 50.030 & 50.220(c)(1)(D)]

58.4. Source testing for emissions of total particulate matter, sulfur compounds, nitrogen compounds, carbon monoxide, lead, volatile organic compounds, fluorides, sulfuric acid mist, municipal waste combustor organics, metals, and acid gases must be conducted in accordance with the methods and procedures specified in 40 C.F.R. 60, Appendix A.

[18 AAC 50.040(a)(3) & 50.220(c)(1)(E)]
[40 C.F.R. 60, Appendix A]

58.5. Source testing for emissions of $PM_{2.5}$ and PM_{10} must be conducted in accordance with the procedures specified in 40 C.F.R. 51, Appendix M, Methods 201 or 201A and 202.

[18 AAC 50.035(b)(2) & 50.220(c)(1)(F)]
[40 C.F.R. 51, Appendix M]

58.6. Source testing for emissions of any pollutant may be determined using an alternative method approved by the Department in accordance with 40 C.F.R. 63 Appendix A, Method 301.

[18 AAC 50.040(c)(32) & 50.220(c)(2)]
[40 C.F.R. 63, Appendix A, Method 301]

59. Excess Air Requirements. To determine compliance with this permit, standard exhaust gas volumes must include only the volume of gases formed from the theoretical combustion of the fuel, plus the excess air volume normal for the specific emissions unit type, corrected to standard conditions (dry gas at 68° F and an absolute pressure of 760 millimeters of mercury).

[18 AAC 50.220(c)(3) & 50.990(102)]

60. Test Exemption. The Permittee is not required to comply with Conditions 62, 63 and 64 when the exhaust is observed for visible emissions by Method 9 Plan (Condition 2.3).

[18 AAC 50.345(a)]

61. Test Deadline Extension. The Permittee may request an extension to a source test deadline established by the Department. The Permittee may delay a source test beyond the original deadline only if the extension is approved in writing by the Department's appropriate division director or designee.

[18 AAC 50.345(a) & (l)]

62. Test Plans. Except as provided in Condition 60, before conducting any source tests, the Permittee shall submit a plan to the Department. The plan must include the methods and procedures to be used for sampling, testing, and quality assurance and must specify how the emissions unit will operate during the test and how the Permittee will document that operation. The Permittee shall submit a complete plan within 60 days after receiving a request under Condition 56 and at least 30 days before the scheduled date of any test unless the Department agrees in writing to some other time period. Retesting may be done without resubmitting the plan.

[18 AAC 50.345(a) & (m)]

63. Test Notification. Except as provided in Condition 60, at least 10 days before conducting a source test, the Permittee shall give the Department written notice of the date and the time the source test will begin.

[18 AAC 50.345(a) & (n)]

64. Test Reports. Except as provided in Condition 60, within 60 days after completing a source test, the Permittee shall submit one certified copy of the results in the format set out in the *Source Test Report Outline*, adopted by reference in 18 AAC 50.030. The Permittee shall certify the results in the manner set out in Condition 67. If requested in writing by the Department, the Permittee must provide preliminary results in a shorter period of time specified by the Department.

[18 AAC 50.345(a) & (o)]

65. Particulate Matter Calculations. In source testing for compliance with the PM standards in Conditions 6 and 21.2, the three-hour average is determined using the average of three one-hour test runs.

[18 AAC 50.220(f)]

Section 7. General Recordkeeping and Reporting Requirements

Recordkeeping Requirements

66. The Permittee shall keep all records required by this permit for at least five years after the date of collection, including:

[18 AAC 50.040(a)(1) & 50.326(j)]
[40 C.F.R 60.7(f), Subpart A, 40 C.F.R 71.6(a)(3)(ii)(B)]

66.1. Copies of all reports and certifications submitted pursuant to this section of the permit; and

66.2. Records of all monitoring required by this permit, and information about the monitoring including:

a. the date, place, and time of sampling or measurements;

b. the date(s) analyses were performed;

c. the company or entity that performed the analyses;

d. the analytical techniques or methods used;

e. the results of such analyses; and,

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

Reporting Requirements

67. Certification. The Permittee shall certify any permit application, report, affirmation, or compliance certification submitted to the Department and required under the permit by including the signature of a responsible official for the permitted stationary source following the statement: *"Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete."* Excess emission reports must be certified either upon submittal or with an operating report required for the same reporting period. All other reports and other documents must be certified upon submittal.

67.1. The Department may accept an electronic signature on an electronic application or other electronic record required by the Department if

a. a certifying authority registered under AS 09.80.020 verifies that the electronic signature is authentic; and

b. the person providing the electronic signature has made an agreement, with the certifying authority described in Condition 67.1.a, that the person accepts or agrees to be bound by an electronic record executed or adopted with that signature.

[18 AAC 50.345(a) & (j), 50.205, & 50.326(j)]

68. Submittals. Unless otherwise directed by the Department or this permit, the Permittee shall submit one certified copy of reports, compliance certifications, and/or other submittals required by this permit to ADEC, Air Permits Program, 610 University Ave., Fairbanks, AK 99709-3643, ATTN: Compliance Technician. The Permittee may submit the documents electronically or by hard copy.

68.1. Provide electronic submittals, either by:

a. E-mail using dec.aq.airreports@alaska.gov; or

b. using the Department's Air Online Services at http://dec.alaska.gov/applications/air/airtoolsweb/.

[18 AAC 50.326(j)]
[40 C.F.R. 71.6(a)(3)(iii)(A)]

69. Information Requests. The Permittee shall furnish to the Department, within a reasonable time, any information the Department requests in writing to determine whether cause exists to modify, revoke and reissue, or terminate the permit or to determine compliance with the permit. Upon request, the Permittee shall furnish to the Department copies of records required to be kept by the permit. The Department may require the Permittee to furnish copies of those records directly to the Federal Administrator.

[18 AAC 50.345(a) & (i), 50.200, & 50.326(a) & (j)]
[40 C.F.R. 71.5(a)(2) & 71.6(a)(3)]

70. Excess Emissions and Permit Deviation Reports.

70.1. Except as provided in Condition 53, the Permittee shall report all emissions or operations that exceed or deviate from the requirements of this permit as follows:

a. In accordance with 18 AAC 50.240(c), as soon as possible after the event commences or is discovered, report

(i) emissions that present a potential threat to human health or safety; and

(ii) excess emissions that the Permittee believes to be unavoidable;

b. In accordance with 18 AAC 50.235(a), within two working days after the event commenced or was discovered, report an unavoidable emergency, malfunction, or nonroutine repair that causes emissions in excess of a technology based emission standard; and

c. Report all other excess emissions and permit deviations

(i) within 30 days of the end of the month during which the excess emissions or deviation occurred, except as provided in Conditions 70.1.c(ii) and 70.1.c(iii); or

(ii) if a continuous or recurring excess emissions is not corrected within 48 hours of discovery, within 72 hours of discovery unless the Department provides written permission to report under Condition 70.1.c(i); and

(iii) for failure to monitor, as required in other applicable conditions of this permit.

70.2. When reporting either excess emissions or permit deviations, the Permittee shall report using either the Department's online form, which can be found at http://dec.alaska.gov/applications/air/airtoolsweb, or if the Permittee prefers, the form contained in Section 12 of this permit. The Permittee must provide all information called for by the form that is used.

70.3. If requested by the Department, the Permittee shall provide a more detailed written report to follow up on an excess emissions report.

[18 AAC 50.235(a)(2), 50.240(c), 50.326(j)(3), & 50.346(b)(2) & (3)]

71. Operating Reports. During the life of this permit[23], the Permittee shall submit to the Department an operating report by August 1 for the period January 1 to June 30 of the current year and by February 1 for the period July 1 to December 31 of the previous year.

71.1. The operating report must include all information required to be in operating reports by other conditions of this permit, for the period covered by the report.

71.2. If excess emissions or permit deviations that occurred during the reporting period are not reported under Condition 71.1, the Permittee shall identify

a. the date of the deviation;

b. the equipment involved;

c. the permit condition affected;

d. a description of the excess emissions or permit deviation; and

e. any corrective action or preventive measures taken and the date of such actions; or

71.3. When excess emissions or permit deviations have already been reported under Condition 70 the Permittee shall cite the date or dates of those reports.

71.4. The operating report shall include a listing of emissions monitored under Conditions 2.3.e and 32.2.a(ii) which trigger additional testing or monitoring, whether or not the emissions monitored exceed an emission standard. The Permittee shall include in the report.

a. the date of the emissions;

b. the equipment involved;

c. the permit condition affected; and

[23] *Life of this permit* is defined as the permit effective dates, including any periods of reporting obligations that extend beyond the permit effective dates. For example if a permit expires prior to the end of a calendar year, there is still a reporting obligation to provide operating reports for the periods when the permit was in effect.

d. the monitoring result which triggered the additional monitoring.

71.5. **Transition from expired to renewed permit**. For the first period of this renewed operating permit, also provide the previous permit's operating report elements covering that partial period immediately preceding the effective date of this renewed permit.

[18 AAC 50.346(a) & 50.326(j)]
[40 C.F.R. 71.6(a)(3)(iii)(A)]

72. Annual Compliance Certification. Each year by March 31, the Permittee shall compile and submit to the Department an annual compliance certification report according to Condition 68.

72.1. Certify the compliance status of the stationary source over the preceding calendar year consistent with the monitoring required by this permit, as follows:

a. identify each term or condition set forth in Section 3 through Section 9, that is the basis of the certification;

b. briefly describe each method used to determine the compliance status;

c. state whether compliance is intermittent or continuous; and

d. identify each deviation and take it into account in the compliance certification;

72.2. **Transition from expired to renewed permit**. For the first period of this renewed operating permit, also provide the previous permit's annual compliance certification report elements covering that partial period immediately preceding the effective date of this renewed permit.

72.3. In addition, submit a copy of the report directly to the Clean Air Act Compliance Manager, US EPA Region 10, Mail Stop: OCE-101, 1200 Sixth Avenue, Suite 900, Seattle, WA 98101.

[18 AAC 50.205, 50.345(a) & (j), & 50.326(j)]
[40 C.F.R. 71.6(c)(5)]

73. Emission Inventory Reporting. The Permittee shall submit to the Department reports of actual emissions, by emissions unit, of CO, NH_3, NOx, PM_{10}, $PM_{2.5}$, SO_2, VOCs and Lead (Pb) (and lead compounds) using the form in Section 13 of this permit, as follows:

73.1. Each year by April 30, if the stationary source's potential to emit for the previous calendar year equals or exceeds:

a. 250 TPY of NH_3, PM_{10}, $PM_{2.5}$ or VOCs; or

b. 2,500 TPY of CO, NO_X or SO_2.

73.2. Every third year by April 30, if the stationary source's potential to emit for the previous calendar year (except **actual** emissions for Pb) equals or exceeds:

a. 0.5 TPY of **actual** Pb, or

b. 1,000 TPY of CO; or

c. 100 TPY of SO_2, NH_3, PM_{10}, $PM_{2.5}$, NO_X or VOCs.

73.3. For reporting under Condition 73.2, the Permittee shall report in 2018 for calendar year 2017, 2021 for calendar year 2020, etc., in accordance with the Environmental Protection Agency set schedule.

73.4. Include in the report required by this condition, the required data elements contained within the form in Section 13 or those contained in Tables 2a and 2b of Appendix A to Subpart A of 40 C.F.R. 51 and Emission Inventory Instructions available in Air Online Services (AOS) system for each emissions unit.

a. Submit the report through electronic online submission via the Department's AOS system at http://dec.alaska.gov/applications/air/airtoolsweb using the Permittee Portal option.

b. If the AOS system is not available, the report may be submitted by

(i) email using dec.aq.airreports@alaska.gov; or

(ii) hard copy to the following address: ADEC Air Permits Program, ATTN: Emissions Inventory, 555 Cordova Street, Anchorage, Alaska 99501.

[18 AAC 50.040(j)(4), 50.200, & 50.346(b)(8)]
[40 C.F.R. 51.15, 51.30(a)(1) & (b)(1), & 40 C.F.R. 51, Appendix A to Subpart A]

Section 8. Permit Changes and Renewal

74. Permit Applications and Submittals. The Permittee shall comply with the following requirements for submitting application information to the US Environmental Protection Agency (EPA):

74.1. The Permittee shall provide a copy of each application for modification or renewal of this permit, including any compliance plan, or application addenda, at the time the application or addendum is submitted to the Department;

74.2. The information shall be submitted to the Part 70 Operating Permit Program, US EPA Region 10, Mail Stop: OAW-150, 1200 Sixth Avenue, Suite 900, Seattle, WA 98101.

74.3. To the extent practicable, the Permittee shall provide to EPA applications in portable document format (pdf), MS Word format (.doc), or other computer-readable format compatible with EPA's national database management system; and

74.4. The Permittee shall maintain records as necessary to demonstrate compliance with this condition.

[18 AAC 50.040(j)(7), 50.326(a) & (j)(3), and 50.346(b)(7))]
[40 C.F.R. 71.10(d)(1)]

75. Emissions Trading. 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 the permit.

[18 AAC 50.040(j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(8)]

76. Off Permit Changes. The Permittee may make changes that are not addressed or prohibited by this permit other than those subject to the requirements of 40 C.F.R. Part 72 through 78 or those that are modifications under any provision of Title I of the Act to be made without a permit revision, provided that the following requirements are met:

76.1. Each such change shall meet all applicable requirements and shall not violate any existing permit term or condition;

76.2. Provide contemporaneous written notice to EPA and the Department of each such change, except for changes that qualify as insignificant under 18 AAC 50.326(d) – (i). Such written notice shall describe each such change, including the date, any change in emissions, pollutants emitted, and any applicable requirement that would apply as a result of the change;

76.3. The change shall not qualify for the shield under 40 C.F.R. 71.6(f);

76.4. The Permittee shall keep a record describing changes made at the stationary source that result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from those changes.

[18 AAC 50.040(j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(12)]

77. Operational Flexibility. The Permittee may make CAA Section 502(b)(10)[24] changes within the permitted stationary source without requiring a permit revision if the changes are not modifications under any provision of Title I of the Act and 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):

77.1. The Permittee shall provide EPA and the Department with a written notification no less than seven days in advance of the proposed change.

77.2. For each such change, the notification required by Condition 77.1 shall include a brief description of the change within the permitted stationary source, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change.

77.3. The permit shield described in 40 C.F.R. 71.6(f) shall not apply to any change made pursuant to Condition 77.

[18 AAC 50.040(j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(13)]

78. Permit Renewal. To renew this permit, the Permittee shall submit to the Department[25] an application under 18 AAC 50.326 no sooner than **March 13, 2022** and no later than **March 13, 2023**. The renewal application shall be complete before the permit expiration date listed on the cover page of this permit. Permit expiration terminates the stationary source's right to operate unless a timely and complete renewal application has been submitted consistent with 40 C.F.R. 71.7(b) and 71.5(a)(1)(iii).

[18 AAC 50.040(j)(3), 50.326(c)(2) & (j)(2)]
[40 C.F.R. 71.5(a)(1)(iii) & 71.7(b) & (c)(1)(ii)]

[24] As defined in 40 C.F.R. 71.2, CAA Section 502(b)(10) changes are changes that contravene an express permit term. Such changes do not include changes that would violate applicable requirements or contravene federally enforceable permit terms and conditions that are monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements.

[25] Submit permit applications to the Department's Anchorage office. The current address is: Air Permit Intake Clerk, ADEC, 555 Cordova Street, Anchorage, AK 99501.

Section 9. Compliance Requirements

General Compliance Requirements

79. Compliance with permit terms and conditions is considered to be compliance with those requirements that are

79.1. included and specifically identified in the permit; or

79.2. determined in writing in the permit to be inapplicable.

[18 AAC 50.326(j)(3) & 50.345(a) & (b)]
[40 C.F.R. 71.6(f)(1)]

80. The Permittee must comply with each permit term and condition. Noncompliance with a permit term or condition constitutes a violation of AS 46.14, 18 AAC 50, and, except for those terms or conditions designated in the permit as not federally enforceable, the Clean Air Act, and is grounds for

80.1. an enforcement action;

80.2. permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280; or

80.3. denial of an operating permit renewal application.

[18 AAC 50.040(j), 50.326(j) & 50.345(a) & (c)]

81. It is not a defense in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with a permit term or condition.

[18 AAC 50.326(j)(3) & 50.345(a) & (d)]

82. The Permittee shall allow the Department or an inspector authorized by the Department, upon presentation of credentials and at reasonable times with the consent of the owner or operator to

82.1. enter upon the premises where a source subject to the permit is located or where records required by the permit are kept;

82.2. have access to and copy any records required by the permit;

82.3. inspect any stationary source, equipment, practices, or operations regulated by or referenced in the permit; and

82.4. sample or monitor substances or parameters to assure compliance with the permit or other applicable requirements.

[18 AAC 50.326(j)(3) & 50.345(a) & (h)]

83. For applicable requirements that will become effective during the permit term, the Permittee shall meet such requirements on a timely basis.

[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 71.6(c)(3) & 71.5(c)(8)(iii)(B)]

Section 10. Permit As Shield from Inapplicable Requirements

In accordance with AS 46.14.290, and based on information supplied in the permit application, this section of the permit contains the requirements determined by the Department not to be applicable to the stationary source.

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

84.1. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section; or

84.2. The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance.

[18 AAC 50.326(j)]
[40 C.F.R. 71.6(f)(3)(i)) & (ii)]

85. Table C identifies the emissions units that are not subject to the specified requirements at the time of permit issuance. If any of the requirements listed in Table C becomes applicable during the permit term, the Permittee shall comply with such requirements on a timely basis including, but not limited to, providing appropriate notification to EPA, obtaining a construction permit and/or an operating permit revision.

[18 AAC 50.326(j)]
[40 C.F.R. 71.6(f)(1)(ii)]

Table C - Permit Shields Granted

Non-Applicable Requirements	Reason for Non-Applicability
Gas-Fired Turbines: EU IDs 500 and 501	
40 C.F.R. 60 Subpart A §60.7(a)(1) & (3) - Notification and Recordkeeping (Initial Notification) §60.8(a) - Performance Test, (Initial Performance Test Only)	Obsolete requirements - completed as required.
§60.7(a)(4) - Notification and Recordkeeping	This requirement only applies to "existing facilities", as defined in 40 C.F.R. 60.2.
40 C.F.R. 60 Subpart GG §60.332(a)(1) - Standards for NOx	Standard applies to Electric Utility Stationary Gas Turbines, as defined in subpart. Source is not an Electric Utility Stationary Gas Turbine as defined in Subpart GG.
§60.334(a), (b), & (d) - Monitoring of Operations §60.335(b)(4) - Test Methods and Procedures	Applies only to affected turbines equipped with water injection to control emissions of NOx. Source is not equipped with water injection to control emissions of NOx.
§60.334(e) & (f) - Monitoring of Operations	Applies only to affected turbines that commenced construction after July 8, 2004. Emissions units commenced construction prior to this date.

Non-Applicable Requirements	Reason for Non-Applicability
§60.334(g) - Monitoring of Operations	Applies only to affected turbines subject to the continuous monitoring requirements of 60.334(a), (d), or (f).
§60.334(h) (2) - Monitoring of Operations (Fuel Nitrogen Only)	Savant has not claimed an allowance for fuel bound nitrogen to calculate the applicable NOx emission limit under §60.332.
40 C.F.R. 60 Subpart KKKK	The emissions units have not commenced construction, modification, or reconstruction after February 18, 2005
40 C.F.R. 63 Subpart YYYY	The affected facilities are on the North Slope and the stationary source is not a major source of HAPs.
All Storage Tanks	
40 C.F.R. 60 Subpart Kb	All storage tanks at the Badami Development Facility either meet 40 C.F.R. 60.110b(b), which exempts tanks that have a capacity greater than 151 cubic meters storing a liquid with a maximum true vapor pressure less than 3.5 kPa or with a capacity greater than 75 cubic meters but less than 151 cubic meters storing a liquid with a maximum true vapor pressure less than 15 kPa, or do not meet the applicability requirements in 40 C.F.R. 60.110b(a) and are not affected sources under 40 C.F.R. 60 Subpart Kb.
Incinerators: EU IDs 422 and 502	
18 AAC 50.050(b)	The limits of the standard do not apply to incinerators with a rated capacity less than 1000 pounds per hour.
40 C.F.R. 60 Subparts AAAA, CCCC, and EEEE	EU ID 502 has not commenced construction, modification, or reconstruction within the applicability dates covered under Subparts AAAA (after August 30, 1999), CCCC (after June 4, 2010), and EEEE (after December 9, 2004). EU ID 422 does not meet the definition of "municipal waste combustion unit" under Subpart AAAA and does not meet the applicability dates covered under Subparts CCCC and EEEE.
40 C.F.R. 62 Subpart III (EU ID 422 only)	EU 422 has not commenced construction, modification, or reconstruction on or before November 30, 1999. In addition, 40 C.F.R. 60 Subpart DDDD (Emissions Guidelines and Compliance Times for Commercial and Industrial Solid Waste Incineration Units) has revised the definition of "cyclonic burn barrel" as "not an incinerator, a waste-burning kiln, an energy recovery unit or a small, remote incinerator under this subpart." EU ID 422 is a Smart Ash Model 100A cyclonic burn barrel.
Gas-Fired Heaters and Reboilers: EU IDs 503 and 505	
40 C.F.R. 60 Subpart D	Heat input capacities below threshold (250 MMBtu/hr).
40 C.F.R. 60 Subpart Da	Heat input capacities below threshold (250 MMBtu/hr); and units not classified as Electric Utility Steam Generating Units, as defined in subpart.
40 C.F.R. 60 Subpart Db	Heat input capacities below threshold (100 MMBtu/hr).
40 C.F.R 63 Subpart DDDDD	The stationary source is not a major source of HAPs.

Non-Applicable Requirements	Reason for Non-Applicability
Gas-Fired Reboilers: EU ID 505	
40 C.F.R. 60 Subpart Dc	Heat input capacities below threshold (10 MMBtu/hr).
40 C.F.R. 63 Subpart JJJJJJ	Per 40 C.F.R. 63.11195(e), gas-fired boilers are not subject to Subpart JJJJJJ and to any requirements in this subpart.
Liquid Fuel-Fired Heaters: EU IDs 607, 608, 611, 612, and BAD 022 (IEUs)	
40 C.F.R. 60 Subpart D, Da, Db, Dc	Heat input capacities below threshold (10 - 250 MMBtu/hr).
40 C.F.R. 63 Subpart JJJJJJ	These heaters do not meet the definition of "boilers" in §63.11237 because the units do not use water to recover thermal energy in the form of steam and/or hot water.
Liquid Fuel-Fired Engine: EU IDs 420a and 421a	
40 C.F.R. 60 Subpart IIII §60.4209(b), Monitoring Requirements for units equipped with a diesel particulate filter §60.4214(c), Recordkeeping Requirements for units equipped with a diesel particulate filter	The emissions units are non-emergency CI ICEs not equipped with a diesel particulate filter to comply with the emission standards in 40 CFR 60.4204.
§60.4214(a), Notification, Reports, and Records	40 C.F.R. 60.4214(a) applies only to owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified. EU IDs 420a and 421a do not meet these criteria.
§60.4212, Testing Requirements	The emissions units meet the standards by being an engine certified to the applicable emission standards. Therefore, performance testing is not required.
§60.4213, Testing Methods	The displacements for EU IDs 420a and 421a are < 30 liters/cylinder.
40 C.F.R. 63 Subpart ZZZZ	Per 40 C.F.R. 63.6590(c)(1), affected emissions units that are new stationary CI RICE must meet the requirements of 40 C.F.R. 63 Subpart ZZZZ by meeting the requirements of 40 C.F.R. 60 Subpart IIII and no further requirements apply for such engines under 40 C.F.R. 63 Subpart ZZZZ.
Flare: EU ID 507	
40 C.F.R. 60.18, Subpart A – General Control Device Requirements	This flare is not control devices used to comply with applicable Subparts of 40 C.F.R. 60 and 40 C.F.R. 61.
All Nonroad Engines and Incinerators	
18 AAC 50.055(a)(1) – Fuel-Burning Equipment Emission Standards: Visible Emissions 18 AAC 50.055(b)(1) – Fuel-Burning Equipment Emissions Standards: Particulate Matter 18 AAC 50.055(c) – Fuel-Burning Equipment Emissions Standards: Sulfur Compound Emissions	Nonroad (mobile) internal combustion engines and incinerators are not included in the definition of "fuel-burning equipment" or "industrial processes," as defined in 18 AAC 50.990(39) and (49)..

Non-Applicable Requirements	Reason for Non-Applicability
Stationary Source-Wide	
40 C.F.R. 61 National Emission Standards for HAPs – Subpart J	No process components in *benzene service*, as defined under 40 C.F.R. 61.111(10 percent benzene by weight).
40 C.F.R. 61 Subpart V	Stationary source does not operate equipment in volatile hazardous air pollutant (VHAP) service, as defined under 40 C.F.R. 61.241 (≥10 percent VHAP by weight).
40 C.F.R. 61 Subpart Y	Stationary source does not operate storage vessels in benzene service.
40 C.F.R. 61 Subpart BB	Stationary source does not conduct benzene transfer operations.
40 C.F.R. 61 Subpart FF	Stationary source does not conduct benzene waste operations.
40 C.F.R. 61 Subpart M §61.142 - Standard for Asbestos Mills	Stationary source is not an Asbestos Mill.
§61.143 - Standards for Roadways	Stationary source roadways not exposed to asbestos tailings or asbestos containing waste.
§61.144 - Standard for Manufacturing	Stationary source does not engage in any manufacturing operations using commercial asbestos.
§61.146 - Standard for Spraying	Stationary source does not spray apply asbestos containing materials.
§61.147 - Standard for Fabricating	Stationary source does not engage in any fabricating operations using commercial asbestos.
§61.148 - Standard for Insulating Materials	Stationary source does not install or reinstall, on any facility component, insulation material containing commercial asbestos.
§61.149 - Standard for Waste Disposal for Asbestos Mills	Applies only to those facilities subject to §61.142 (Asbestos Mills).
§61.151 - Standard for Inactive Waste Disposal Sites for Asbestos Mills and Manufacturing and Fabricating Operations	Applies only to those stationary sources subject to §§61.142, 61.144, or 61.147 (Asbestos Mills, manufacturing or fabricating).
§61.152 - Standard for Air-Cleaning	Stationary source does not use air cleaning equipment.
§61.153 - Standard for Reporting	No reporting requirements apply for sources subject to §61.145 (demolition and renovation)[ref. §61.153(a)].
§61.154 - Standards for Active Waste Disposal Sites	Stationary source not an active waste disposal site and does not receive asbestos containing waste material.
§61.155 - Standard for Inactive Waste Disposal Sites for Asbestos Mills and Manufacturing and Fabricating Operations	Stationary source does not process regulated asbestos containing material (RACM).
40 C.F.R. 63 Subpart HH, Oil and Fuel gas Production Facilities	Per 40 C.F.R. 63.760(e)(1), the stationary source is exempt from the requirements of 40 C.F.R. 63, Subpart HH. The stationary source exclusively processes, stores, or transfers black oil.
40 C.F.R. 68 - Chemical Accidental Prevention Provisions	The stationary source does not have more than a threshold quantity of a regulated substance in a process.

Non-Applicable Requirements	Reason for Non-Applicability
40 C.F.R. 82 Subpart B – Servicing of Motor Vehicle Air Conditioners	Stationary source and its employees do not perform service on motor vehicle air conditioners, for consideration or otherwise.
Activities subject to 40 C.F.R. 61 Subpart M – Standard for Demolition and Renovation (§61.145)	
40 C.F.R. 61 National Emission Standards for HAPs – Subpart A: §61.05(a) - Prohibited Activities §61.07 - Application for Approval of Construction or Modification §61.09 -Notification of Startup	Owners or operators of demolition and renovation operations are exempt from the requirements of §§61.05(a), 61.07, and 61.09[ref. 40 C.F.R. 61. 145(a)(5)].
§61.10 - Source Reporting and Waiver Request	Demolition and renovation operations are exempt from §61.10(a) [ref. 40 C.F.R. 61.153(b)].
§61.13 -Emission Tests §61.14 - Monitoring Requirements	Emission tests or monitoring is not required under the standards for demolition and renovation [§61.145].

Section 11. Visible Emissions Forms

VISIBLE EMISSION OBSERVATION FORM

This form is designed to be used in conjunction with EPA Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources." Temporal changes in emission color, plume water droplet content, background color, sky conditions, observer position, etc. should be noted in the comments section adjacent to each minute of readings. Any information not dealt with elsewhere on the form should be noted under additional information. Following are brief descriptions of the type of information that needs to be entered on the form: for a more detailed discussion of each part of the form, refer to "Instructions for Use of Visible Emission Observation Form" (a copy is available in https://www3.epa.gov/ttnemc01/methods/webinar8.pdf).

- Source Name: full company name, parent company or division or subsidiary information, if necessary.
- Address: street (not mailing or home office) address of facility where visible emissions observation is being made.
- Phone (Key Contact): number for appropriate contact.
- Source ID Number: number from NEDS, agency file, etc.
- Process Equipment, Operating Mode: brief description of process equipment (include type of facility) and operating rate, % capacity, and/or mode (e.g. charging, tapping, shutdown).
- Control Equipment, Operating Mode: specify type of control device(s) and % utilization, control efficiency.
- Describe Emission Point: for identification purposes, stack or emission point appearance, location, and geometry; and whether emissions are confined (have a specifically designed outlet) or unconfined (fugitive).
- Height Above Ground Level: stack or emission point height relative to ground level; can use engineering drawings, Abney level, or clineometer.
- Height Relative to Observer: indicate height of emission point relative to the observation point.
- Distance from Observer: distance to emission point; can use rangefinder or map.
- Direction from Observer: direction plume is traveling from observer.
- Describe Emissions and Color: include physical characteristics, plume behavior (e.g., looping, lacy, condensing, fumigating, secondary particle formation, distance plume visible, etc.), and color of emissions (gray, brown, white, red, black, etc.). Note color changes in comments section.
- Visible Water Vapor Present?: check "yes" if visible water vapor is present.
- If Present, note in the Comments column whether the Plume is "attached" if water droplet plume forms prior to exiting stack, and "detached" if water droplet plume forms after exiting stack.
- Point in Plume at Which Opacity was Determined: describe physical location in plume where readings were made (e.g., 1 ft above stack exit or 10 ft. after dissipation of water plume).
- Describe Plume Background: object plume is read against, include texture and atmospheric conditions (e.g., hazy).
- Background Color: sky blue, gray-white, new leaf green, etc.
- Sky Conditions: indicate color of clouds and cloud cover by percentage or by description (clear, scattered, broken, overcast).
- Wind Speed: record wind speed; can use Beaufort wind scale or hand-held anemometer to estimate.
- Wind Direction From: direction from which wind is blowing; can use compass to estimate to eight points.
- Ambient Temperature: in degrees Fahrenheit or Celsius.
- Wet Bulb Temperature: can be measured using a sling psychrometer
- RH Percent: relative humidity measured using a sling psychrometer; use local US Weather Bureau measurements only if nearby.
- Source Layout Sketch: include wind direction, sun position, associated stacks, roads, and other landmarks to fully identify location of emission point and observer position.
- Draw North Arrow: to determine, point line of sight in direction of emission point, place compass beside circle, and draw in arrow parallel to compass needle.
- Sun's Location: point line of sight in direction of emission point, move pen upright along sun location line, mark location of sun when pen's shadow crosses the observer's position.
- Observation Date: date observations conducted.
- Start Time, End Time: beginning and end times of observation period (e.g., 1635 or 4:35 p.m.).
- Data Set: percent opacity to nearest 5%; enter from left to right starting in left column. Use a second (third, etc.) form, if readings continue beyond 30 minutes. Use dash (-) for readings not made; explain in adjacent comments section.
- Comments: note changing observation conditions, plume characteristics, and/or reasons for missed readings.
- Range of Opacity: note highest and lowest opacity number.
- Observer's Name: print in full.
- Observer's Signature, Date: sign and date after performing VE observation.
- Observer's Affiliation: observer's employer.
- Certifying Organization, Certified By, Date: name of "smoke school," certifying observer and date of most recent certification.

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR PERMITS PROGRAM - VISIBLE EMISSIONS OBSERVATION FORM

Page No.

Stationary Source Name	Type of Emission Unit	Observation Date	Start Time	End Time
Emission Unit Location				
City / State / Zip				
Phone # (Key Contact)	Stationary Source ID Number			
Process Equipment	Operating Mode			
Control Equipment	Operating Mode			
Describe Emission Point/Location				
Height above ground level / Height relative to observer / Clinometer Reading				
Distance From Observer Start / End	Direction From Observer Start / End			
Describe Emissions & Color Start	End			
Visible Water Vapor Present? If yes, determine approximate distance from the stack exit to where the plume was read (No / Yes)				
Point in Plume at Which Opacity Was Determined				
Describe Plume Background	Background Color			
Start	Start			
End	End			
Sky Conditions: Start	End			
Wind Speed Start / End	Wind Direction From Start / End			
Ambient Temperature	Wet Bulb Temp / RH percent			

SOURCE LAYOUT SKETCH: 1 Stack or Point Being Read 2 Wind Direction From
3 Observer Location 4 Sun Location 5 North Arrow 6 Other Stacks

Sec	0	15	30	45	Comments
Min 1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					

Additional Information:

Range of Opacity:
Minimum | Maximum

I have received a copy of these opacity observations
Print Name:
Signature:
Title | Date

Print Observer's Name
Observer's Signature | Date
Observer's Affiliation:

Certifying Organization:
Certified By: | Date

Data Reduction:

Duration of Observation Period (minutes):
Number of Observations:
Number of Observations exceeding 20%:
In compliance with six-minute opacity limit? (Yes or No)

Duration Required by Permit (minutes):
Highest Six–Minute Average Opacity (%):
Highest 18-Consecutive –Minute Average Opacity (%)(engines and turbines only)

Average Opacity Summary:

Set Number	Time			Opacity		
	Start	End		Sum	Average	Comments

Section 12. Notification Form[26]

Badami Development Facility — **Stationary Source Name**

AQ0417TVP03 — **Air Quality Permit Number.**

Savant Alaska, LLC — **Company Name**

When did you discover the Excess Emissions/Permit Deviation?

Date: _____ / _____ / _____ Time: _____ :/ _____

When did the event/deviation occur?

Begin: Date: _____ / _____ / _____ Time: _____ : _____ (please use 24-hr clock.)

End: Date: _____ / _____ / _____ Time: _____ : _____ (please use 24-hr clock)

What was the duration of the event/deviation? ____ : ____ (hrs:min) or _____ days

(total # of hrs, min, or days, if intermittent then include only the duration of the actual emissions/deviation)

Reason for Notification: (please check only 1 box and go to the corresponding section)

☐ Excess Emissions – Complete Section 1 and Certify

☐ Deviation from Permit Condition – Complete Section 2 and Certify

☐ Deviations from COBC, CO, or Settlement Agreement – Complete Section 2 and Certify

Section 1. Excess Emissions

(a) **Was the exceedance** ☐ Intermittent or ☐ Continuous

(b) **Cause of Event** (Check one that applies):

☐ Start Up/Shut Down ☐ Natural Cause (weather/earthquake/flood)

☐ Control Equipment Failure ☐ Schedule Maintenance/Equipment Adjustment

☐ Bad Fuel/Coal/Gas ☐ Upset Condition ☐ Other _____

(c) **Description**

Describe briefly, what happened and the cause. Include the parameters/operating conditions exceeded, limits, monitoring data and exceedance.

[26] Revised as of September 27, 2010.

(d) **Emissions Units Involved:**
Identify the emissions unit involved in the event, using the same identification number and name as in the permit. Identify each emission standard potentially exceeded during the event and the exceedance.

EU ID	EU Name	Permit Condition Exceeded/Limit/Potential Exceedance

(e) **Type of Incident** (please check only one):

☐ Opacity _____ % ☐ Venting _____ gas/scf ☐ Control Equipment Down
☐ Fugitive Emissions ☐ Emission Limit Exceeded ☐ Recordkeeping Failure
☐ Marine Vessel Opacity ☐ Flaring ☐ Other

(f) **Unavoidable Emissions:**

Do you intend to assert that these excess emissions were unavoidable? ☐ Yes ☐ No

Do you intend to assert the affirmative defense of 18 AAC 50.235? ☐ Yes ☐ No

Certify Report (go to end of form)

Section 2. Permit Deviations

(a) **Permit Deviation Type** (check only one box corresponding with the section in the permit):

☐ Emissions Unit-Specific
☐ Failure to Monitor/Report
☐ General Source Test/Monitoring Requirements
☐ Recordkeeping/Reporting/Compliance Certification
☐ Standard Conditions Not Included in the Permit
☐ Other Section: _____ (Title of section and section number of your permit).
☐ Generally Applicable Requirements
☐ Reporting/Monitoring for Diesel Engines
☐ Insignificant Emissions Unit
☐ Stationary Source Wide

(b) **Emissions Units (EU) Involved:**

Identify the emissions units involved in the event, using the same identification number and name as in the permit. List the corresponding permit conditions and the deviation.

EU ID	EU Name	Permit Condition/ Potential Deviation

(c) **Description of Potential Deviation:**

Describe briefly what happened and the cause. Include the parameters/operating conditions and the potential deviation.

(d) **Corrective Actions:**

Describe actions taken to correct the deviation or potential deviation and to prevent future recurrence.

Certification:

Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.

Printed Name: _____ Title: _____ Date: _____

Signature: _____ Phone Number: _____

NOTE: *This document must be certified in accordance with 18 AAC 50.345(j)*

To Submit this Report:

1. Fax to: 907-451-2187

   Or

2. Email to: DEC.AQ.Airreports@alaska.gov

   Or

3. Mail to: ADEC
   Air Permits Program
   610 University Avenue
   Fairbanks, AK 99709-3643

   Or

4. Phone Notifications: 907-451-5173
   Phone notifications require a written follow-up report.

An online version of this notification form is found at the following website:
http://dec.alaska.gov/applications/air/airtoolsweb/

If submitted online, report must be submitted by an authorized E-Signer for the stationary source.

[18 AAC 50.346(b)(3)]

Section 13. Emission Inventory Form

A detailed instruction on development and submission of emission inventory is available at the Department's Air Online Services (AOS) at http://dec.alaska.gov/Applications/Air/airtoolsweb/PointSourceEmissionInventory by clicking on "Emission Inventory Instructions" button.

ADEC Reporting Form **Emission Inventory Reporting** State of Alaska Department of Environmental Conservation Division of Air Quality	**Emission Inventory Year- [ ]**

Mandatory information is highlighted in bright yellow. Make additional copies as needed.

Stationary Source Detail		
Inventory Start Date		
Inventory End Date		
ADEC ID or Permit Number		
EPA ID		
Census Area/Community		
Facility Name		
Facility Physical Location	**Address**	
	City, State, Zip Code	
	Latitude	**Longitude**
	Legal Description:	
Owner Name		
Owner Address		
Owner contact number		
Mailing Contact Information	**Address**	
	City, State, Zip Code	
Line of Business (NAICS)		
Facility Status		

Emissions Unit Data			
Specifications			
ID		Design Capacity	
Description			
Emission Unit Status			
Manufacturer		Manufactured Year	
Model Number		Serial Number	
Regulations			
Regulation/Description			

Control Equipment (List All if applicable)			
ID			
System Description			
Equipment Type(s)			
Manufacturer			
Model			
Control Efficiency (%):			
Capture Efficiency (%)			
Pollutants Controlled		Reduction Efficiency (%)	
		Reduction Efficiency (%)	

Processes			
Process			
SCC Code			
Material Processed			
Period Start			
Period End			
Throughput (units):			
Summer %			
Fall %			
Winter %			
Spring %			
Operational Schedule			
Days/Week			
Hours/Day			
Weeks/Year			
Hours/Year			
Fuel Characteristics			
Heat Content	Elem. Sulfur Content (%)	H2S Sulfur Content	Ash Content (if applicable)
Heating			
Heat Input		Heat Output	Heat Values Convention

Emission Operating Type					
Pollutant	**Emission Factor**	**EF Numerator**	**EF Denominator**	**Emission Calculation Method**	**Tons**
Carbon Monoxide (CO)					
Nitrogen Oxides (NOX)					
PM10 Primary (PM10-PRI)					
PM2.5 Filterable (PM25-FIL)[27]					
PM Condensable (PM-CON)[28]					
Sulfur Dioxide (SO2)					
NH3 (Ammonia)					
Lead and lead compounds					
Volatile Organic Compounds (VOC)					
Emissions' Release Point					
Release Point ID					
Apportion%					

[27] Report PM-2.5 filterable and PM condensable portions of the PM-2.5 Primary emissions, as applicable, in accordance with Federal Regulation 40 CFR 51.15(a)(1)(vi). Refer to EPA's May 2017 "Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations" (see Section 4.2.1) for guidance on the reporting of PM-2.5 filterable and condensable emissions.

[28] Please note on the inventory form if there is no available emission factor that can be used for an applicable condensable PM. For example, EPA AP-42 Table 3.3-1 does not contain a condensable PM emission factor for diesel engines smaller than 600 hp.

Process	Secondary Process (if applicable)				
SCC Code	(ex. 20100201)				
Material Processed					
Period Start					
Period End					
Throughput (units):					
Summer %					
Fall %					
Winter %					
Spring %					
Operational Schedule					
Days/Week					
Hours/Day					
Weeks/Year					
Hours/Year					
Fuel Characteristics					
Heat Content	Elem. Sulfur Content	H2S Sulfur Content		Ash Content (if applicable)	
Heating					
Heat Input		Heat Output		Heat Values Convention	
Emissions Operating Type:					
Pollutant	Emission Factor	EF Numerator	EF Denominator	Emission Calculation Method	Tons
Carbon Monoxide (CO)					
Nitrogen Oxides (NOX)					
PM10 Primary (PM10-PRI)					
PM2.5 Primary (PM25-PRI)					
Sulfur Dioxide (SO2)					
Lead and Lead Compounds					
NH3 (Ammonia)					
Volatile Organic Compounds (VOC)					
Emissions' Release Point					
Release Point ID					
Apportion%					

Stack Detail (Release Point)	
> Specifications	
ID	
Type	
Description	
Stack Status	
> Stack Parameters	
Stack Height (ft)	
Stack Diameter (ft)	
Exit Gas Temp (F)	
Exit Gas Velocity (fps)	
Exit Gas Flow Rate (acfm)	
> Geographic Coordinate	
Latitude	
Longitude	
Datum	
Accuracy (meters)	
Base Elevation (meters)	

Certification:

Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.

Printed Name:_____Title_____Date _____

Signature:_____Phone number_____

NOTE: *This document must be certified in accordance with 18 AAC 50.345(j)*

To Submit this report:

1. Direct data entry for emission inventory can be done through the Air Online System (AOS) http://dec.alaska.gov/Applications/Air/airtoolsweb/. A myAlaska account is needed to gain access and a profile needs to be set up in Permittee Portal OR

2. E-mail to: DEC.AQ.airreports@alaska.gov

Or

3. Mail to: ADEC
   Air Permits Program
   ATTN: Emissions Inventory
   555 Cordova Street
   Anchorage, Alaska 99501

Or

4. Fax this form to: 907-269-7508

[18 AAC 50.346(b)(9)]

ATTACHMENT
PERMIT NO. AQ0417MSS05

DEPARTMENT OF ENVIRONMENTAL CONSERVATION

AIR QUALITY CONTROL MINOR PERMIT

Permit No. AQ0417MSS05 Final – April 26, 2013
Rescinds Permit No. AQ0417MSS03, Revision 1

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Minor Permit No. AQ0417MSS05 to the Permittee listed below.

Operator and Permittee:	**Savant Alaska, LLC** 7401 Village Square Drive, Suite 102 Castle Rock, CO 80108
Owner:	Savant Alaska, LLC
Stationary Source	Badami Development Facility
Location:	UTM Zone 6, Northing: 7782.6 km; Easting: 496.4 km
Physical Address:	North Slope, Alaska
Permit Contact:	Zane Henning, (907) 448-6013
Project:	Revise Restart Provisions

This project is classified under 18 AAC 50.508(6) for revising or rescinding the terms and conditions of a Title I permit. The permit satisfies the obligation of the Permittee to obtain a minor permit under 18 AAC 50.

As required by AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this permit.

John F. Kuterbach
Manager, Air Permits Program

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Section 1. Emission Unit Inventory

1. Inventory. Except as noted elsewhere in the permit the information in Table 1 is for information purposes only. The specific unit descriptions do not restrict the Permittee from replacing an emission unit (EU) identified in Table 1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement EU, including any applicable minor or construction permit requirements.

Table 1: Minor Permit EU Inventory

EU ID	Description	Make/Model	Rating/Size	Fuel Type	Installed[a]
Stationary Emission Units					
417	Diesel Tank	Unknown	15,000 bbl	Diesel	1997
418	Methanol Tank	Unknown	450 bbl	Methanol	1997
419	Glycol Skid Heater	Unknown	1.05 MMBtu/hr	Diesel	1998
420a[b]	Generator	Cummins QSK50-G4	1,971 hp	Diesel	2013
421a[c]	Generator	Cummins QSK50-G4	1,971 hp	Diesel	2010[c]
500	Turbine	Solar Mars 90	11,862 kW	Natural Gas	1998
501	Turbine	Solar Mars 90	11,862 kW	Natural Gas	1998
502	Incinerator, Waste Combustion	Therm-Tec G-12	1.6 MMBtu/hr 85 lb/hr	Propane/Natural Gas/Waste	
503	Production Heater	NATCO	34 MMBtu/hr	Natural Gas	1998
504	Miscible Injection Heater	NATCO	14.87 MMBtu/hr	Natural Gas	1998
505	TEG Reboiler	NATCO	1.34 MMBtu/hr	Natural Gas	1998
507	Flare-Produced Gas	Mac Ignitor 100 Series	257.9 MMscf/yr	Natural Gas	1998
508	110 barrel TEG Storage Tank	Unknown	110 bbl	N/A	1998
Portable Equipment					
422	Smart Ash Incinerator	Smart Ash 100-A	0.035 tons/hr	Oily Waste	
601	Light Plants	Unknown	12.1 hp	Diesel	
602	Light Plants	Unknown	12.1 hp	Diesel	
607	Heaters-Indirect fire heaters	Unknown	1 MMBtu/hr	Diesel	
608	Heaters-Indirect fire heaters	Unknown	1 MMBtu/hr	Diesel	
611	Heaters-Indirect fire heaters	Unknown	1 MMBtu/hr	Diesel	
612	Heaters-Indirect fire heaters	Unknown	1 MMBtu/hr	Diesel	
Drill Rig Equipment[d]					
1	Rig Engines	Unknown	Unknown	Diesel	
8	Rig Boilers and Heaters	Unknown	Unknown	Diesel	

Table Notes:
[a] Installed dates obtained from Table 1 of Permit Nos. AQ0417TVP01 Revision 2 and AQ0417MSS03.
[b] EU ID 420a replaced EU ID 420 in April 2013.
[c] EU ID 421a replaced EU ID 421, authorized by Permit No. AQ0417MSS03 issued on October 20, 2010
[d] The Permittee is authorized to operate any drill rig with a cumulative rating equal to or less than the largest approved drill rig in Operating Permit No. AQ0455TVP01, Revision 3 (or subsequent renewals and revisions).

Section 2. Emission Fees

2. Assessable Emissions. The Permittee shall pay to the Department an annual emission fee based on the stationary source's assessable emissions as determined by the Department under 18 AAC 50.410. The assessable emission fee rate is set out in 18 AAC 50.410(b). The Department will assess fees per ton of each air pollutant that the stationary source emits or has the potential to emit in quantities greater than 10 tons per year (tpy). The quantity for which fees will be assessed is the lesser of

2.1 the stationary source's assessable potential to emit of 1,475 TPY; or

2.2 the stationary source's projected annual rate of emissions that will occur from July 1 to the following June 30, based upon actual annual emissions emitted during the most recent calendar year or another 12-month period approved in writing by the Department, when demonstrated by

a. an enforceable test method described in 18 AAC 50.220;

b. material balance calculations;

c. emission factors from EPA's publication AP-42, Vol. I, adopted by reference in 18 AAC 50.035; or

d. other methods and calculations approved by the Department**.**

3. Assessable Emission Estimates. Emission fees will be assessed as follows:

3.1 no later than March 31 of each year, the Permittee may submit an estimate of the stationary source's assessable emissions to ADEC, Air Permits Program, ATTN: Assessable Emissions Estimate, 410 Willoughby Ave., Juneau, AK 99801-1795; the submittal must include all of the assumptions and calculations used to estimate the assessable emissions in sufficient detail so the Department can verify the estimates; or

3.2 if no estimate is submitted on or before March 31 of each year, emission fees for the next fiscal year will be based on the potential to emit set forth in Condition 2.1.

Section 3. State Requirements

4. Industrial Process and Fuel-Burning Equipment Visible Emissions. The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from EU IDs 419 – 422, 500, 501 – 505, and 507 listed in Table 1 to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.

5. Industrial Process and Fuel-Burning Equipment Particulate Matter. The Permittee shall not cause or allow particulate matter emitted from EU IDs 419 – 421a, 500, 501, 503 – 505, and 507 listed in Table 1 to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.

6. Sulfur Compound Emissions. The Permittee shall not cause or allow sulfur compound emissions, expressed as SO_2, from EU IDs 419 – 422, 500, 501 – 505, and 507 to exceed 500 ppm averaged over three hours.

Section 4. Ambient Air Quality Standards and Increments

7. The Permittee shall not interfere with the attainment or maintenance of the Ambient Air Quality Standards listed in 18 AAC 50.010, and shall not cause or contribute to a violation of the maximum allowable increases (the PSD increments) listed in 18 AAC 50.020 as follows:

7.1 **EU ID 507 (Flare) Limit.** Flare natural gas quantities during the routine or non-routine maintenance activities and other planned events. The Permittee shall flare produced gas quantities no greater than 152 MMscf of natural gas during any 12 consecutive month period, at a rate of no greater than 20 MMscf per day.

a. The Permittee shall record the date and duration when gas flaring occurs, and the quantity of gas flared.

b. The Permittee shall report in the Operating Report required by the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50, the duration of gas flaring and the total quantity of gas flared; describe or document whether the flaring incident is considered an emergency operation, routine or no-routine maintenance operation, or other planned event.

7.2 **Air Quality Boundary.** Establish and maintain the ambient boundaries used in the ambient impact analysis using the following procedures:

a. Comply with the May 10, 2005 "CPF Pad Badami Unit – Public Access Control Plan" (Plan), or a subsequent written version approved by the Department that contains at least the following elements:

(i) a topographic map (or maps) that clearly show(s) the ambient boundaries, water bodies and Central Process Facility (CPF) pad;

(ii) ambient boundaries that are consistent with the land owner's authorization to preclude public access from the area within the boundaries;

(iii) defined methods of establishing and maintaining the boundary; and

(iv) the date of the revised Public Access Control Plan.

b. Do not revise the ambient air boundaries without Department approval. If requested by the Department, submit a revised ambient air impact analysis that demonstrates that the emission activities will not cause or contribute to ambient air violations when using the proposed boundary.

c. Submit all proposed revisions of the Plan, including the ambient boundary, to the Department's Juneau and Fairbanks offices. Do not implement any change without written Department approval.

8. Fuel Gas Sulfur Limit. Operate the natural gas-fired EUs using natural gas fuel with a hydrogen sulfide (H_2S) content not to exceed 250 parts per million by volume (ppmv).

8.1 The Permittee shall obtain a statement or receipt from the fuel supplier identifying the total fuel sulfur content of the fuel gas used in the gas fired emission units. If a statement or receipt is not available from the supplier, then analyze a representative sample of the fuel to determine the sulfur content using a method described in the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50.

8.2 The Permittee shall report in the Operating Report required by the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50

a. copies of vendor statements or receipts; or

b. analysis reports for fuel sulfur content.

9. Diesel Fuel Sulfur Limit. Operate the diesel fuel-fired emission units (except for intermittently used oil field equipment[1]) using diesel fuel with a fuel sulfur content not to exceed 0.15 percent sulfur by weight (wt% S).

9.1 The Permittee shall obtain a statement or receipt from the fuel supplier identifying the fuel grade or the total fuel sulfur content of the diesel fuel used in the diesel fired emission units. If a statement or receipt is not available from the supplier, then analyze a representative sample of the fuel to determine the sulfur content using a method described in the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50.

9.2 The Permittee shall report in the Operating Report required by the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50.

a. copies of vendor statements or receipts; or

b. analysis reports for fuel sulfur content.

10. EU IDs 420a and 421a Liquid Fuel Consumption Limits. In EU IDs 420a and 421a, burn a combined total of no more than 800,000 gallons of liquid fuel during any 12 consecutive month period.

10.1 Install and operate a dedicated fuel meter accurate to less than five percent error for EU ID 420a and 421a combined; and install and operate a dedicated continuous engine hour monitoring system for each unit.

10.2 Monitor and record the monthly fuel consumption for EU IDs 420a and 421a combined, and the monthly hours of operation for each unit.

10.3 Except as provided in Condition 10.4, calculate and record the 12 consecutive month combined fuel consumption using fuel meter data.

[1] This permit does not impose fuel sulfur restrictions on intermittently used oil field support equipment. The Department has instead established off-permit fuel sulfur targets for these units in Policy and Procedure Number 04.02.105 (effective November 20, 2006).

10.4 If the fuel meter for EU IDs 420a and 421a is out of service, estimate the gallons of fuel consumed for the emission units using the hours of operation recorded in Condition 10.2, assuming the 100 percent load fuel consumption rate in gallons per hour for the unit for any period during which the unit was operating. The fuel consumption rate shall be the design fuel consumption of 97.8 gallons per hour.

10.5 Report in the Operating Report required by the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50:

a. the monthly and 12 consecutive month total fuel consumption for EU IDs 420a and 421a combined; and

b. if the hours of operation were used to calculate the fuel use for any part of the 12 month rolling period as described in condition 10.4, report the monthly and 12 consecutive month hours of operation for EU IDs 420a and 421a.

11. EU IDs 1 and 8 (Drill Rig) Liquid Fuel Consumption Limits. In all drill rig emission units, burn a combined total of no more than 9,000 gallons of liquid fuel per day and 950,000 gallons of liquid fuel during any 12 consecutive month period.

11.1 Monitor and record for each operational day, the quantity of the fuel combusted in drill rig emission units, combined. Calculate and record the 12 consecutive month total fuel consumption.

11.2 Report in the Operating Report required by the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50 the maximum daily fuel consumption, and the 12 consecutive month fuel consumption for all drill rig emission units, combined.

Section 5. Best Available Control Technology (BACT)

12. The Permittee shall install emission or operational controls as BACT for the following equipment:

12.1 **Initial BACT Limits.**

a. NOx BACT for fuel burning equipment at Badami is no post-combustion emission control with good operational practices.

(i) The Permittee shall install and operate as BACT for the following fuel burning equipment at Badami:

(A) EU IDs 500 and 501 with dry low NOx combustion technology (SoLoNOx);

(B) EU IDs 420a and 421a with a modular common rail system (MCRS) as incorporated by the manufacturer;

(C) EU ID 503 with low NOx burners/flue gas recirculation;

(D) EU ID 504 with conventional burner technology; and

(E) EU ID 505 with conventional burner technology.

(ii) The Permittee shall comply with the following NOx emission limits. Emissions from:

(A) EU IDs 500 and 501 shall not exceed 28.4 lb NOx/hr for operation under all conditions, and shall not exceed 85 ppmv corrected to 15 percent oxygen in SoLoNOx mode and at ambient temperatures above 0°F;

(B) EU ID 503 shall not exceed 0.095 lb NOx/MMBtu;

(C) EU ID 504 shall not exceed 0.12 lb NOx/MMBtu; and

(D) EU ID 505 shall not exceed 0.08 lb NOx/MMBtu.

b. CO BACT for fuel burning equipment at Badami is no post-combustion emission control with good operational practices. The Permittee shall comply with the following CO emission limits as representative of BACT. Emissions from:

(i) EU IDs 500 and 501 shall not exceed 50 ppmv corrected to 15 percent oxygen when operating at 100 percent load in SoLoNOx mode at ambient temperatures above 0°F, 14 lb/hr when operating in SoLoNOx mode and at ambient temperatures above 0°F, and 385 lb/hr for operation under all other conditions;

(ii) EU ID 503 shall not exceed 0.10 lb CO/MMBtu;

(iii) EU ID 504 shall not exceed 0.12 lb CO/MMBtu; and

(iv) EU ID 505 shall not exceed 0.15 lb CO/MMBtu.

c. Limit CO emissions from EU IDs 500 and 501, combined, to no greater than 336 tons per 12-consecutive month period.

d. SO_2 BACT for fuel burning equipment at Badami is use of low sulfur fuel with no post-combustion controls. The Permittee shall comply with the following fuel sulfur limits as representative of BACT:

(i) H_2S content of natural gas fuel shall not exceed 250 ppmv; and

(ii) sulfur content of fuel oil shall not exceed 0.15 wt% S.

e. VOC BACT for fuel burning equipment and fuel storage tanks, and water treatment processes at Badami is no controls with good operation practices. BACT for water injection tanks and slop tank is a sealed system design. The flare BACT determination is smokeless tip design. No emission limits are imposed as representing BACT.

f. PM less than 10 microns (PM-10) BACT for fuel burning equipment at Badami is no controls with good operation practices. The Permittee shall comply with the following surrogate PM-10 emission limits as representative of BACT.

(i) Visible emission from EU IDs 420a and 421a shall not exceed:

(A) 20 percent opacity averaged over any six consecutive minutes, at all times except as described in Condition 12.1f(i)(B); and

(B) if both oil and gas production cease for 30 consecutive days, EU ID 420a and 421a shall not exceed 10 percent opacity averaged over any six consecutive minutes thereafter, until oil and gas production resumes.

(ii) EU IDs 500 and 501 shall not exceed 10 percent opacity averaged over any six consecutive minutes.

(iii) All other industrial processes, incinerators, and fuel-burning equipment shall comply with the applicable State visible emission standards listed in the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50.

12.2 **Monitoring and Recordkeeping.**

a. NOx and CO—The Permittee shall monitor and record compliance as follows:

(i) For EU IDs 500 and 501:

(A) Using the existing computer-based control system[2], monitor and record:

(1) operating time in hours (record time in minutes or decimal portions of an hour);

(2) for each hour, the average percentage natural gas producer (% NGP) speed (use six minute intervals to calculate the average % NGP speed for each hour of operation); and

(3) for each hour, time in and out of SoLoNOx operation for each unit.

(B) Calculate and record the hourly CO emissions for EU IDs 500 and 501. Use the SoLoNOx mode and the hourly average % NGP speed (as determined in Condition 12.2a(i)(A)(2)) to determine the appropriate CO emission factor listed in Table 2 or alternate CO emission factors approved in writing by the Department. Multiply the appropriate CO emission factor by the associated hours of operation to get hourly CO emissions.

(C) On calendar month basis, calculate and record the total monthly and 12-consecutive month period CO emissions for EU ID 500 and 501 individually, and EU ID 500 and 501 combined.

b. SO_2—The Permittee shall conduct fuel sulfur monitoring and recordkeeping in accordance with the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50.

c. PM—The Permittee shall conduct visible emission surveillance monitoring in accordance with the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50.

(i) Except as indicated in Condition 12.2c(ii), conduct the surveillance on EU IDs 420a and 421a no less than once per calendar quarter. Indicate on the surveillance form if the unit observed is subject to the 10 percent PM-10 BACT limit described in Condition 12.1f(i)(B).

(ii) If four consecutive quarters show compliance with the applicable limit listed in Condition 12.1f(i), for a given unit, then the Permittee may reduce the frequency of visible emission observations required in Condition 12.2c(i) for that limit and that unit to no less than once per calendar year.

12.3 **Reporting.** The Permittee shall:

[2] For any time the computer based system is out of order, the Permittee shall estimate and record the hourly operating time, % NGP speed, and time in and out of SoLoNOx operation for each unit.

a. CO--Report the monthly and 12 consecutive month total CO emission for EU IDs 500 and 501, each, and the combined total.

b. SO_2--Report fuel sulfur content as required by the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50.

c. PM-10--Report the results of the visible emission surveillance reports as required by the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50.

Section 6. Restart Project

13. Limits on Use of Load Banks. Except as provided in Condition 14, after February 1, 2013, the Permittee shall not use load banks, water brakes, pump flow controls or other loads that have the single purpose to destroy energy in order to improve the CO emission performance of EU IDs 500 and 501. For purposes of this permit, a load bank is a resistance device that performs no process or space heating function.

14. The Permittee may use a load bank on a short term basis to address intermittent power fluctuations that may occur as a result of bringing on a second turbine for project ramp-up, with the plan of operating both turbines simultaneously. Monitor, record and report as follows.

14.1 **Monitoring and Recordkeeping.** Record each change in the load bank power use in kW in a written log, noting date, time, and "before" and "after" settings of load bank power use:

a. at each instance the load is adjusted; and

b. twice daily coincident with physical inspections of the load bank, whenever load bank is receiving power.

14.2 **Reporting.** Report in the Operating Report required by the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50:

a. the number of hours the load bank was used; and

b. a statement whether the load bank was used to address intermittent power fluctuations as a result of bringing on a second turbine for project ramp-up.

14.3 **Excess Emissions and Permit Deviations.** If load banks were used for purposes other than to address intermittent power fluctuations, as a result of bringing on a second turbine for project ramp-up as specified in Condition 14, report as a permit deviation as described in the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50.

15. EU IDs 500 and 501 NOx and CO Restart BACT Requirements. The Permittee shall affirm existing or re-assess NOx BACT, and assess CO BACT for EU IDs 500 and 501 as described below.

15.1 **Baseline Period.** The Baseline Period for purposes of this section is the 12 months following February 1, 2013. The Department may extend the Baseline Period for good cause shown.

a. **Monitoring and Recordkeeping.** For the Baseline Period, the Permittee shall monitor and record for EU IDs 500 and 501 for each hour:

(i) total run time;

(ii) time in SoLoNOx; and

(iii) emission unit operating mode (normal, startup, shut down, malfunction, maintenance, load transfer, and source testing).

b. **Reporting.** The Permittee shall report the information listed in Condition 15.1a within 30 days after the end of the Baseline Period.

15.2 If EU IDs 500 and 501, combined, operate in SoLoNOx mode for less than 95 percent of aggregate operating hours during the Baseline Period, excluding startup, shut down, malfunction, maintenance, load transfer, and source testing, then within 75 days after the end of the Baseline Period, the Permittee shall submit an application as follows:

a. for installing new appropriately sized turbines to replace EU IDs 500 and 501, based on operations during the Baseline Period; or

b. for re-assessing BACT for NOx and CO for EU IDs 500 and 501 based on operations during the Baseline Period following EPA's "top-down" BACT assessment methodology as provided in EPA's 1990 Draft New Source Workshop Manual. The BACT assessment shall include the following elements:

(i) cost estimates and supporting data specific for Badami, cost indexed for the year that the analysis is provided;

(ii) the cost elements used in the BACT cost analysis must be accompanied with copies of the original vendor quotes, including the scope of supply services; and

(iii) the cost analysis to be performed according to the guidelines as set out in the "EPA Air Pollution Control Cost Manual", latest edition.

c. After the permit issuance under Condition 15.2, install BACT as determined in Condition 15.2b.

Table 2: Badami Restart Solar Gas Turbine CO Emission Factors

EU IDs	SoLoNOx Mode	Gas Turbine Load Condition (% NGP)	CO Emission Factor
500, 501	Solar Mars 90 SoloNOx gas turbine	% NGP speed average hourly value	
	In SoloNOx mode		**4.7 lb/hr**
	Out SoloNOx mode	% NGP ≥ 94	4.7 lb/hr
		% NGP ≥ 90 and < 94	202.0 lb/hr
		% NGP ≥ 87 and < 90	236.0 lb/hr
		% NGP ≥ 84 and < 87	261.9 lb/hr
		% NGP < 84	385 lb/hr

Section 7. General Conditions

Standard Terms and Conditions

16. The Permittee must comply with each permit term and condition. Noncompliance with a permit term or condition constitutes a violation of AS 46.14, 18 AAC 50, and, except for those terms or conditions designated in the permit as not federally enforceable, the Clean Air Act, and is grounds for

16.1 an enforcement action; or

16.2 permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280.

17. It is not a defense in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with a permit term or condition.

18. Each permit term and condition is independent of the permit as a whole and remains valid regardless of a challenge to any other part of the permit.

19. The permit may be modified, reopened, revoked and reissued, or terminated for cause. A request by the Permittee for modification, revocation and reissuance, or termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

20. The permit does not convey any property rights of any sort, nor any exclusive privilege.

Section 8. Permit Documentation

August 23, 2012	Savant and their Consultants (Cardno ENTRIX) met with the Department to provide an update on Badami.
October 9, 2012	The Department sent an email to Cardno ENTRIX summarizing the Department's position on the issues Savant raised in the August 23, 2012 meeting.
October 24, 2012	Savant, Cardno ENTRIX, and the Department met again to continue discussions on Badami.
November 28, 2012	Savant submits a complete application to revise Minor Permit AQ0417MSS03 Revision 1 (Restart Provisions).
January 16, 2013	Savant submitted a minor revision to their suggested permit condition for monitoring and recording load bank power consumption.
January 23, 2013	Savant submitted more data on the fuel consumption of EU ID 420 in response to a Department request.
February 13, 2013	Mathew Cohen (on behalf of Savant) sent email to John Kuterbach of the Department suggesting permit language for the BACT section of the permit.
February 27, 2013	The Department sent an email to Savant describing what the Department considers an acceptable BACT analysis for the Badami Restart Project.
February 28, 2013	In an email to John Kuterbach, Savant agrees to perform a rigorous BACT analysis if the Baseline Period compels a BACT analysis, so long as the Department does not prescribe a minimum control technology requirement before the analysis is performed. Savant will send edited proposed permits to the Department that would address John's concerns.
February 28, 2013	Sally Ryan (on behalf of Savant) sent an updated redline preliminary permit and TAR to the Department.
March 11, 2013	Jeanette Brena (on behalf of Savant) in a phone conversation with Zeena Siddeek (of the Department) requested the Department to provide the legal authority that allows the Department to include source testing to demonstrate compliance with short term BACT limits.
March 11, 2013	In an email to Jeanette, the Department responded to Savant's 'legal authority' request by citing 18 AAC 50.544(i) which allows the Department to include conditions necessary to ensure compliance and AS 46.14.280 that allows the Department to modify a permit that contains a material mistake.
March 12, 2012	John Kuterbach sent an email to Matthew Cohen, Zeena, and Savant consultants summarizing the various emails concerning Minor Permit AQ0417MSS05. John directed his staff to issue a preliminary permit without re-establishing the monitoring provisions for the short term BACT limits and provide written notice to Savant that the Department will modify AQ0417TVP01 to correct a material mistake and establish monitoring for the BACT limits.
March 12, 2013	Matthew Cohen sent an email to John Kuterbach accepting John Kuterbach's suggestions. Matthew proposed a path forward for issuing he the minor permit and saving the BACT monitoring for the preliminary

	renewal Title V permit. The Department can include source testing to show compliance with the short term BACT limits.
March 13, 2013	John Kuterbach sent an email to Matthew Cohen accepting Matthew Cohen's proposed path forward. The preliminary minor permit will not contain source testing and periodic monitoring of the BACT limits. The renewal Title V permit will address the BACT monitoring.
April 26, 2013	Savant sent an email to the Department suggesting wording of the footnote 'd' in Table 1. The footnote authorizes Savant to operate any drill rig approved in Operating Permit AQ0455TVP01, Revision 3 (or subsequent renewals and revisions). The Department accepted the suggested wording.

ATTACHMENT
PERMIT NO. AQ0417MSS06

DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY CONTROL MINOR PERMIT

Permit No. AQ0417MSS06 Final – April 27, 2015
Revises Permit No. AQ0417MSS05

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Minor Permit No. AQ0417MSS06 to the Permittee listed below.

Permittee:	**Savant Alaska, LLC** P.O. Box 112212 Anchorage, AK 99511-2212
Owner/Operator:	Same as Permittee
Stationary Source	Badami Development Facility
Location:	UTM Zone 6, Northing: 7782.6 km; Easting: 496.4 km
Physical Address:	North Slope, Alaska
Permit Contact:	Robert Crotty, (907) 433-7808, robert.crotty@savantalaska.com
Project:	Revise CO BACT Limit for EU ID 503

This project is classified under 18 AAC 50.508(6) for revising or rescinding the terms and conditions of a Title I permit. The permit satisfies the obligation of the Permittee to obtain a minor permit under 18 AAC 50.

As required by AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this permit.

for John F. Kuterbach
Manager, Air Permits Program

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Section 1. Recission

1. Sub-Condition 12.1b of Minor Permit AQ0417MSS05 is rescinded.

Section 2. Best Available Control Technology (BACT)

2. CO BACT for fuel burning equipment at Badami is no post-combustion emission control with good operational practices. The Permittee shall:

2.1 Comply with the following CO emission limits as representative of BACT:

a. EU IDs 500 and 501 shall not exceed 50 ppmv corrected to 15 percent oxygen when operating at 100 percent load in SoLoNOx mode at ambient temperatures above 0°F, 14 lb/hr when operating in SoLoNOx mode and at ambient temperatures above 0°F, and 385 lb/hr for operation under all other conditions;

b. EU ID 503 shall not exceed 3.4 lb CO/hr;

c. EU ID 504 shall not exceed 0.12 lb CO/MMBtu; and

d. EU ID 505 shall not exceed 0.15 lb CO/MMBtu.

Section 3. Standard Terms and Conditions

3. The Permittee must comply with each permit term and condition. Noncompliance with a permit term or condition constitutes a violation of AS 46.14, 18 AAC 50, and, except for those terms or conditions designated in the permit as not federally enforceable, the Clean Air Act, and is grounds for

3.1 an enforcement action; or

3.2 permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280.

4. It is not a defense in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with a permit term or condition.

5. Each permit term and condition is independent of the permit as a whole and remains valid regardless of a challenge to any other part of the permit.

6. The permit may be modified, reopened, revoked and reissued, or terminated for cause. A request by the Permittee for modification, revocation and reissuance, or termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

7. The permit does not convey any property rights of any sort, nor any exclusive privilege.

Section 4. Permit Documentation

November 7, 2014 Application for Minor Permit AQ0417MSS06

ATTACHMENT
PERMIT NO. AQ0417MSS07, Rev.1

DEPARTMENT OF ENVIRONMENTAL CONSERVATION

AIR QUALITY CONTROL MINOR PERMIT

Permit No. AQ0417MSS07, Revision 1 Final – July 08, 2015
Revises Permit No. AQ0417MSS05

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Minor Permit No. AQ0417MSS07, Revision 1 to the Permittee listed below.

Permittee:	**Savant Alaska, LLC** P.O. Box 112212 Anchorage, AK 99511-2212
Owner/Operator:	Same as Permittee
Stationary Source	Badami Development Facility
Location:	UTM Zone 6, Northing: 7782.6 km; Easting: 496.4 km
Physical Address:	North Slope, Alaska
Permit Contact:	Robert Crotty, (907) 433-7808, robert.crotty@savantalaska.com
Project:	Revise Fuel Type for Drill Rig EUs

This project is classified under 18 AAC 50.508(6) for revising or rescinding the terms and conditions of a Title I permit. The permit satisfies the obligation of the Permittee to obtain a minor permit under 18 AAC 50.

As required by AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this permit.

for John F. Kuterbach, Manager
Air Permits Program

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Section 1. Recission

1. Condition 1 and Table 1 of Minor Permit No. AQ0417MSS05 are rescinded and replaced by Condition 3 and Table 1 of Minor Permit No. AQ0417MSS07, Revision 1.

2. Condition 11 of Minor Permit No. AQ0417MSS05 is rescinded and replaced by Condition 4 of Minor Permit No. AQ0417MSS07, Revision 1.

Section 2. Emission Unit Inventory

3. Inventory. Except as noted elsewhere in the permit the information in Table 1 is for information purposes only. The specific unit descriptions do not restrict the Permittee from replacing an emission unit (EU) identified in Table 1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement EU, including any applicable minor or construction permit requirements.

Table 1: Minor Permit EU Inventory

EU ID	Description	Make/Model	Rating/Size	Fuel Type	Installed[a]
Stationary Emission Units					
417	Diesel Tank	Unknown	15,000 bbl	Diesel	1997
418	Methanol Tank	Unknown	450 bbl	Methanol	1997
420a[b]	Generator	Cummins QSK50-G4	1,971 hp	Diesel	2013
421a[c]	Generator	Cummins QSK50-G4	1,971 hp	Diesel	2010[c]
500	Turbine	Solar Mars 90	11,862 kW	Natural Gas	1998
501	Turbine	Solar Mars 90	11,862 kW	Natural Gas	1998
502	Incinerator, Waste Combustion	Therm-Tec G-12	1.6 MMBtu/hr 85 lb/hr	Propane/Natural Gas/Waste	
503	Production Heater	NATCO	34 MMBtu/hr	Natural Gas	1998
505	TEG Reboiler	NATCO	1.34 MMBtu/hr	Natural Gas	1998
507	Flare-Produced Gas	Mac Ignitor 100 Series	257.9 MMscf/yr	Natural Gas	1998
Portable Equipment					
422	Smart Ash Incinerator	Smart Ash 100-A	0.035 tons/hr	Oily Waste	
601	Light Plants	Unknown	12.1 hp	Diesel	
602	Light Plants	Unknown	12.1 hp	Diesel	
607	Heaters-Indirect fire heaters	Unknown	1 MMBtu/hr	Diesel	
608	Heaters-Indirect fire heaters	Unknown	1 MMBtu/hr	Diesel	
611	Heaters-Indirect fire heaters	Unknown	1 MMBtu/hr	Diesel	
612	Heaters-Indirect fire heaters	Unknown	1 MMBtu/hr	Diesel	
Drill Rig Equipment[d]					
1	Rig Engines	Unknown	Unknown	Diesel/Fuel Gas	
8	Rig Boilers and Heaters	Unknown	Unknown	Diesel/Fuel Gas	

Table Notes:
[a] Installed dates obtained from Table 1 of Permit Nos. AQ0417TVP01 Revision 2 and AQ0417MSS03.
[b]EU ID 420a replaced EU ID 420 in April 2013.
[c]EU ID 421a replaced EU ID 421, authorized by Permit No. AQ0417MSS03 issued on October 20, 2010
[d]The Permittee is authorized to operate any drill rig with a cumulative rating equal to or less than the largest approved drill rig in Operating Permit No. AQ0455TVP01, Revision 3 (or subsequent renewals and revisions).
All EUs except dual fuel fired EUs 1 and 8 are authorized by Permit No. AQ0417MSS05
EU ID 419 (1.05 MMBtu/hr glycol skid heater) has been removed from the emission unit inventory; the unit has been removed from the source.
EU ID 504 (miscible injection heater) has been removed from the emission unit inventory; the unit was converted to electric power in 2010 and, therefore, has no emissions.
EU ID 508 (110-barrel TEG storage tank) has been removed from the emission unit inventory; the unit is out of service and is no longer operational.

Section 3. Ambient Air Quality Standards and Increments

4. EU IDs 1 and 8 (Drill Rig) Fuel Consumption Limits. In all drill rig emission units, burn a combined total of no more than 9,000 gallons of liquid fuel per day and 950,000 gallons of liquid fuel during any 12 consecutive month period.

4.1 Monitor and record for each operational day, the quantity of fuel combusted in all drill rig emission units, combined. Monitor fuel gas consumption using non-resettable fuel flow meters.

4.2 Calculate and record the daily combined, and 12 consecutive month combined, total fuel consumption in gallons. For units that are fired with fuel gas, convert the quantity of fuel gas burned (in standard cubic feet (scf)) into a diesel gallon equivalent using the conversion factor of 115 scf of fuel gas to one gallon diesel fuel.

4.3 Report in the Operating Report required by the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50 the maximum daily fuel consumption and the 12 consecutive month total fuel consumption in gallons for all drill rig emission units combined, for each month of the reporting period.

4.4 Report as a permit deviation, in accordance with the operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50 any time the fuel consumption exceeds a limit specified in Condition 4.

Section 4. Standard Terms and Conditions

5. The Permittee must comply with each permit term and condition. Noncompliance with a permit term or condition constitutes a violation of AS 46.14, 18 AAC 50, and, except for those terms or conditions designated in the permit as not federally enforceable, the Clean Air Act, and is grounds for

5.1 an enforcement action; or

5.2 permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280.

6. It is not a defense in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with a permit term or condition.

7. Each permit term and condition is independent of the permit as a whole and remains valid regardless of a challenge to any other part of the permit.

8. The permit may be modified, reopened, revoked and reissued, or terminated for cause. A request by the Permittee for modification, revocation and reissuance, or termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

9. The permit does not convey any property rights of any sort, nor any exclusive privilege.

10. **Air Pollution Prohibited.** No person may permit any emission which is injurious to human health or welfare, animal or plant life, or property, or which would unreasonably interfere with the enjoyment of life or property.

10.1 Monitoring, Recordkeeping, and Reporting for Condition 10

a. If emissions present a potential threat to human health or safety, the Permittee shall report any such emissions in accordance with the operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50.

b. As soon as practicable after becoming aware of a complaint that is attributable to emissions from the stationary source, the Permittee shall investigate the complaint to identify emissions that the Permittee believes have caused or are causing a violation of Condition 10.

10.2 The Permittee shall initiate and complete corrective action necessary to eliminate any violation identified by a complaint or investigation as soon as practicable if

a. after an investigation because of a complaint or other reason, the Permittee believes that emissions from the stationary source have caused or are causing a violation of Condition 10; or

b. the Department notifies the Permittee that it has found a violation of Condition 10.

10.3 The Permittee shall keep records of

a. the date, time, and nature of all emissions complaints received;

b. the name of the person or persons that complained, if known;

c. a summary of any investigation, including reasons the Permittee does or does not believe the emissions have caused a violation of Condition 10; and

d. any corrective actions taken or planned for complaints attributable to emissions from the stationary source.

10.4 With each stationary source operating report required by the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50 the Permittee shall include a brief summary report which must include

a. the number of complaints received;

b. the number of times the Permittee or the Department found corrective action necessary;

c. the number of times action was taken on a complaint within 24 hours; and

d. the status of corrective actions the Permittee or Department found necessary that were not taken within 24 hours.

10.5 The Permittee shall notify the Department of a complaint that is attributable to emissions from the stationary source within 24 hours after receiving the complaint, unless the Permittee has initiated corrective action within 24 hours of receiving the complaint.

11. Assessable Emissions. The Permittee shall pay to the Department an annual emission fee based on the stationary source's assessable emissions as determined by the Department under 18 AAC 50.410. The assessable emission fee rate is set out in 18 AAC 50.410(b). The Department will assess fees per ton of each air pollutant that the stationary source emits or has the potential to emit in quantities greater than 10 tons per year (tpy). The quantity for which fees will be assessed is the lesser of

11.1 the stationary source's assessable potential to emit of 1,475 tpy; or

11.2 the stationary source's projected annual rate of emissions that will occur from July 1 to the following June 30, based upon actual annual emissions emitted during the most recent calendar year or another 12-month period approved in writing by the Department, when demonstrated by

a. an enforceable test method described in 18 AAC 50.220;

b. material balance calculations;

c. emission factors from EPA's publication AP-42, Vol. I, adopted by reference in 18 AAC 50.035; or

d. other methods and calculations approved by the Department**.**

Section 5. Permit Documentation

March 26, 2015	Application for Minor Permit No. AQ0417MSS07, dated March 12, 2015, was received by the Department.

Electronic Copy of Application