

**DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY CONTROL MINOR GENERAL PERMIT**

**MINOR GENERAL PERMIT 2 (MG2)
FOR PORTABLE OIL AND GAS OPERATIONS (POGO)**

Minor General Permit 2 Revision 1

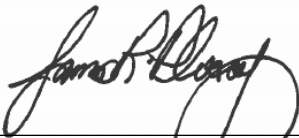
Final Date: July 1, 2023

Rescinds: Minor General Permit 2 issued August 1, 2018

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues this minor general permit to be used for the construction, operation, or relocation of a Portable Oil and Gas Operation (POGO), as described in 18 AAC 50.990(124). This minor general permit satisfies the obligation of the Permittee to obtain a minor permit under 18 AAC 50 and AS 46.14.120(g). As required by AS 46.14.120(c) the Permittee shall comply with the terms and conditions of this permit.

Technical support for permit conditions can be found in the Technical Analysis Report. This permit authorizes the Permittee to operate any emissions unit that meets the requirements listed in this permit. The owner must comply with the applicable requirements at the location where the emissions units operate.

This minor general permit does not expire and is valid until the Department terminates, modifies, reopens, or revokes and reissues the permit. The letter of authorization is in effect until withdrawn, modified, revoked and reissued, or if the source no longer qualifies for this permit. The use of sample forms provided with this permit are not a reporting requirement, however, any independently developed form must contain all the reporting requirements listed within this permit.



James R. Plosay, Manager
Air Permits Program

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Section 1 Emissions Unit Inventory

Emissions Unit (EU) Authorization. The Permittee is authorized to install or relocate, and operate a POGO in accordance with the terms and conditions of this permit. The POGO may consist of one or more drill rigs, along with miscellaneous support equipment. The possible emissions units (EUs) authorized under this permit are listed in Table 1. Unless otherwise noted elsewhere in this permit, the information in Table 1 is for identification purposes only. The specific EU descriptions do not restrict the Permittee from replacing an EU identified in Table 1.

The Permittee is also authorized to concurrently conduct well servicing activities, as defined in 18 AAC 50.990(125),¹ and operate nonroad engines associated with construction activities, in accordance with the terms and conditions of this permit.

Table 1 – EU Inventory

EU ID	EU Name	EU Description	Total Rating/Size
1	Drill Rig Reciprocating Engines	Diesel-fired Nonroad Engines	Varies
2	Drill Rig Heaters and Boilers	Diesel-fired Heaters and Boilers	Varies
3	Well Venting/Flow Backs	N/A	Varies
4	Miscellaneous POGO Reciprocating Engines Not On Drill Rig	Diesel-fired Nonroad Engines	Varies
5	Miscellaneous POGO Heaters and Boilers Not On Drill Rig	Diesel-fired Heaters and Boilers	Varies
6	POGO Portable Flares	Fuel Gas	Varies

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.
2. **Verification of Equipment Specifications and Maintenance of Equipment.** The Permittee shall install and maintain the equipment listed in Table 1 according to the manufacturer’s or operator’s maintenance procedures. Keep a copy of the manufacturer’s or operator’s maintenance procedure onsite and make records available to the Department personnel upon request. The records may be kept in electronic format.

¹ As defined in 18 AAC 50.990(125), “well servicing activities” means the use of portable equipment for servicing existing oil and gas wells that only stays on site for short and varying periods of time; “well servicing activities” includes the use of coiled tubing units, well frac units, well slickline units, well hot oil units, and well wireline units.

Section 2 ***Fee Requirements***

- 3. Fee Requirements.** The Permittee shall pay to the Department all assessed permit fees. Fee rates are set out in 18 AAC 50.400 – 499.
- 4. Assessable Emissions.** The Permittee shall pay to the Department annual emission fees based on the POGO’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. Notwithstanding 18 AAC 50.410(a) – (d), for the POGO projected annual rate of emissions under a general minor permit under 18 AAC 50.560, the emission fee is allocated to the emission control permit receipts accounts under AS 46.14.265, and the Permittee shall pay the emission fee:
- 4.1 At the time of application or notification for operation that will occur during that state fiscal year.
 - 4.2 For operation under a single application or notification during subsequent state fiscal years, after annual emission fee billing under 18 AAC 50.420 for each subsequent state fiscal year.
 - 4.3 For each individual POGO for which the owner or operator submits a new application or notification for operation under the general minor permit, for the first fiscal year of operation, an emission fee specified under 18 AAC 50.410(g)(3).²
 - 4.4 For subsequent state fiscal years, the Department will assess fees³ per ton of each air pollutant that the POGO emits or has the potential to emit. The quantity for which fees will be assessed is the lesser of:
 - a. each individual POGO’s assessable potential to emit of 252.1 tpy; or
 - b. each individual POGO’s projected annual rate of emissions that will occur from July 1st to the following June 30th, 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:
 - (i) an enforceable test method described in 18 AAC 50.220;
 - (ii) material balance calculations;
 - (iii) emission factors from EPA’s publication AP-42, Vol. I, adopted by reference in 18 AAC 50.035; or
 - (iv) other methods and calculations approved by the Department, including appropriate vendor-provided emissions factors when sufficient documentation is provided.
- 5. Assessable Emission Estimates.** Emission fees will be assessed as follows:
- 5.1 No later than March 31 of each year, the Permittee may submit an estimate of the POGO’s assessable emissions as determined in Condition 4.4. Submit actual emission estimates in

² The current MG2 general permit application fee, emission fees, and compliance review fee can all be found under the MG2 section of the Department’s general permits webpage; <https://dec.alaska.gov/air/air-permit/general-permits/>.

³ Assess Title V fees if planning to operate POGO contiguous/adjacent on a Title V source. Assess Title I fees if separate.

accordance with the submission instructions on the Department's Standard Permit Conditions web page at <http://dec.alaska.gov/air/air-permit/standard-conditions/standard-condition-i-submission-instructions/>.

- 5.2 The Permittee shall include with the assessable emission report all of the assumptions and calculations used to estimate the assessable emissions in sufficient detail so the Department can verify the estimates.
 - 5.3 If the stationary source has not commenced construction or operation on or before March 31st, the Permittee may submit to the Department's Anchorage office a waiver letter certified under 18 AAC 50.205 that states the stationary source's actual annual emissions for the previous calendar year are zero TPY and provides estimates for when construction or operation will commence.
 - 5.4 If no estimate or waiver letter 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 in Condition 4.4a.
- 6. Annual Compliance Fee.** For a POGO not classified as needing a Title V permit, the Permittee shall pay an annual compliance fee as set out in 18 AAC 50.400(d)(3)(B)(ii) & (h)², to be paid for each period from July 1st through the following June 30th.

Section 3 Applicability Criteria

7. This minor general permit applies to a POGO that:
 - 7.1 is not located in a non-attainment area;
 - 7.2 does not concurrently operate under an MG1 permit at a given well pad or drill site;
 - 7.3 operates at a given well pad or drill site identified by the application or relocation notification;
 - 7.4 does not operate on a platform⁴ surrounded by open water;
 - 7.5 operates north of 69 degrees, 30 minutes North latitude; and
 - 7.6 maintains the nonroad engine status of EU IDs 1 and 4 as defined in 40 C.F.R. 1068.30.

⁴ The restriction described in Condition 7.4 only applies to platforms. Minor General Permit 2 is applicable to POGOs operating on island developments within the Beaufort Sea.

Section 4 State Emission Standards

- 8. Visible Emissions for Industrial Processes and Fuel-Burning Equipment.** The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from all fuel-burning equipment⁵ listed in Table 1, to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.
- 8.1 For each heater or boiler operated as EU ID 2, verify compliance with Condition 8 by performing one of the following:
- a. Certified Manufacturer Guarantee. Obtain a certified manufacturer guarantee prior to operating the heater or boiler under this permit, that the given heater or boiler will comply with the visible emission standard; or
 - b. Annual Method 9 Observation. Conduct visible emission observations following 40 C.F.R. 60, Appendix A-4, Method 9, for 18 minutes to obtain 72 consecutive 15-second opacity observations, at least once in each calendar year that the heater or boiler, as applicable, operates for at least seven consecutive days under the terms and conditions of this permit.
- 8.2 When using Condition 8.1a to verify compliance of a heater or boiler operated as EU ID 2, attach a copy of the guarantee obtained under Condition 8.1a to the operating report required by Condition 19 that covers the initial period of operation of the heater or boiler under this permit.
- 8.3 Attach a copy of the observation records developed under Condition 8.1b (using the form in Attachment 1) to the operating report required under Condition 19, for the period that covers the dates the observations were conducted.
- 8.4 For each flare operated as EU ID 6 observe one daylight flare event⁶ annually, on a calendar year basis. If there is no qualifying flare event within the calendar year, then the Permittee shall observe the next qualifying daylight flare event for that flare when it is operated onsite.
- a. Observe the flare exhaust following 40 C.F.R. 60, Appendix A-4, Method 9, for 18 minutes to obtain 72 consecutive 15-second opacity observations during flare events.
 - b. Record the following information for observed events:
 - (i) the flare's EU number;
 - (ii) results of the Method-9 observations;
 - (iii) reason for flaring;
 - (iv) date, beginning and ending time of event; and
 - (v) volume of gas flared.

⁵ "Fuel-burning equipment" does not include equipment operated as a nonroad engine, per 18 AAC 50.990(39).

⁶ For purposes of this permit, a "flare event" is flaring of gas during daylight at a rate that exceeds the source's de-minimis pilot, purge, and assist gas rates for a minimum of 18 consecutive minutes. It does not include non-scheduled release operations, i.e., process upsets, emergency flaring, or de-minimis venting of gas incidental to normal operations.

- c. Monitoring of a flare event may be postponed for safety or weather reasons, or because a qualified observer is not available. If a flare event has not yet been observed during a calendar year and 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 19 an explanation of the reason the flare event was not monitored. If no flare events occurred during the reporting period, then no monitoring or reporting is required.
 - d. Include copies of the records required by Condition 8.4b in the operating report submitted under Condition 19 for the period covered by the report.
- 8.5 Report as a permit deviation under Condition 17 if any of Conditions 8.1 through 8.4 are not met.
- 8.6 If the results of Method 9 observations completed under Condition 8 exceed the standard in Condition 8, report as excess emissions in accordance with Condition 17, take corrective actions, and conduct follow-up Method 9 observations as soon as possible after completing corrective actions until the standard in Condition 8 is met.
- 9. Particulate Matter for Industrial Processes and Fuel-Burning Equipment.** The Permittee shall not cause or allow particulate matter emitted from all fuel-burning equipment listed in Table 1, to exceed 0.05 grains per dry standard cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.
- 9.1 For each heater/boiler operated as EU ID 2, conduct a particulate matter source test according to the requirements set out in Section 8 no later than 90 calendar days after any time corrective maintenance fails to eliminate visible emissions greater than the 20 percent opacity threshold for two or more 18-minute observations in a consecutive six-month period.
- 10. Sulfur Compound Emissions for Industrial Processes and Fuel-Burning Equipment.** The Permittee shall not cause or allow sulfur compound emissions, expressed as SO₂, from each fuel-burning equipment listed in Table 1 to exceed 500 parts per million averaged over three hours.
- 10.1 Monitor, record, and report in accordance with Condition 12.2.

Section 5 *Ambient Air Quality Protection Requirements*

- 11.** To protect the 1-hour and annual nitrogen dioxide (NO₂); 24-hour particulate matter with an aerodynamic diameter of 10 microns or less (PM-10); 24-hour and annual particulate matter with an aerodynamic diameter of 2.5 microns or less (PM-2.5); 1-hour, 3-hour, 24-hour, and annual sulfur dioxide (SO₂), and 1-hour and 8-hour carbon monoxide (CO) Alaska Ambient Air Quality Standards (AAAQS), the Permittee shall:
- 11.1 Construct and maintain vertical, uncapped exhaust stacks on all nonroad engines operated as EU ID 1 and all heaters/boilers operated as EU ID 2. This condition does not preclude the use of flapper-style rain covers, or other similar designs, that do not hinder the vertical momentum of the exhaust plume.
- a. Confirm in each operating report required under Condition 19 that the exhaust stack for each nonroad engine operated as EU ID 1, and each heater/boiler operated as EU ID 2, complies with Condition 11.1; or state that no unit was operated as EU IDs 1 or 2 during the reporting period.
- b. Report as described in Condition 17, if a requirement under Condition 11.1 was not met.
- 11.2 Prohibit the hydraulic fracturing (fracking) of unconventional resources⁷ while engaged in POGO activities at a given well pad. Report as described in Condition 17 if fracking of unconventional resources occurs.
- 11.3 Limit the combined daily diesel fuel consumption for all nonroad engines operated as EU ID 1 and all heaters/boilers operated as EU ID 2 on a given well pad or drill site, as specified in Table 2. The Permittee may exceed the applicable limits in Table 2 by up to 25 percent on any six or fewer days in any thirty consecutive days. The not to exceed values (excursion limits) for each daily fuel limit identified in Table 2 are as follows:
- a. $14,700 \times 1.25 = 18,375$ gallons per day (gal/day);
- b. $11,400 \times 1.25 = 14,250$ gal/day; and
- c. $10,700 \times 1.25 = 13,375$ gal/day.

⁷ For the purposes of this permit, *unconventional resources* is differentiated from conventional hydrocarbon resources based on the state of the hydrocarbon, nature of the geologic reservoirs and the types of technologies required to extract the hydrocarbon. Conventional oil and gas deposits have a well-defined areal extent, the reservoirs are porous and permeable, the hydrocarbon is produced easily through a wellbore, and reservoirs generally do not require extensive well stimulation to produce. Unconventional hydrocarbon deposits in general are often lower in resource concentration, dispersed over large areas, and require well stimulation or additional extraction or conversion technology.

Table 2 – EU IDs 1 and 2 Daily Fuel Consumption Limits (gal/day)¹

Fuel Consumption Operational Scenarios	Routine Drilling Isolated (Rdi) ²	Routine Drilling Collocated (RDc) ³	Developmental Drilling Isolated (Ddi) ⁴	Developmental Drilling Collocated (DDc) ⁵
POGO Without Concurrent Hydraulic Fracturing of a Conventional Resource	14,700	11,400	14,700	10,700
POGO With Concurrent Hydraulic Fracturing of a Conventional Resource	11,400	11,400	10,700	10,700

Notes:

1. Daily fuel consumption thresholds apply to the drill rig only and do not apply to other emissions units that may be a part of the POGO or operating on the well pad, such as stationary well pad equipment, portable power generators, or well servicing equipment (as defined in 18 AAC 50.990(125)) – these activities are represented by the background values added to the modeled impacts.
2. Routine Infill Drilling at an Isolated Well Pad: Drilling that lasts less than 24 consecutive months at a well pad that is not adjacent to, adjoining, or abutting a Title V major production facility. For the purpose of this permit the term production facility includes production centers, gathering centers, flow stations, or equivalent.
3. Routine Infill Drilling at a Collocated Well Pad: Drilling that lasts less than 24 consecutive months at a well pad that is adjacent to, adjoining, or abutting a Title V major production facility.
4. Developmental Drilling at an Isolated Well Pad: Drilling that lasts 24 or more consecutive months at a well pad that is not adjacent to, adjoining, or abutting a Title V major production facility.
5. Developmental Drilling at a Collocated Well Pad: Drilling that lasts 24 or more consecutive months at a well pad that is adjacent to, adjoining, or abutting a Title V major production facility.

11.4 Record and report in each operating report required under Condition 19, the following information that applies during the reporting period:

- a. Drill rig identification;
- b. Pad identification
- c. Pad category (collocated or isolated)⁸;
- d. Dates occupied by the rig(s) at each pad;
- e. Drilling category(s) (routine or developmental);
- f. Start and end dates when any nonroad engine operated as EU ID 1 operate concurrently with fracking; and
- g. Start and end dates when any heater/boiler operated as EU ID 2, operate concurrently with fracking.

⁸ For the purpose of this permit, “collocated” means that drill rig(s) and/or existing stationary sources are located on one or more contiguous or adjacent properties that are under the control of the same person (or persons under common control) and shall be considered part of a single “building, structure, or facility.” Pollutant emitting activities (SIC Major Group 13) shall be considered adjacent if they are located on the same surface site; or if they are located on surface sites that are located within 1/4 mile of one another (measured from the center of the equipment on the surface site) and they share equipment. Shared equipment includes, but is not limited to, produced fluids storage tanks, phase separators, natural gas dehydrators, or emissions control devices. Drill sites that are not physically adjacent to or contiguous with a Title V production facility are treated as isolated pads for ambient air quality protection purposes. If a well pad or well site is aggregated with a production facility under an existing Title V permit, but otherwise does not meet the definition of collocated as stated above, that well site or well pad is considered isolated.

- 11.5 For each nonroad engine operated as EU ID 1 and each heater/boiler operated as EU ID 2, determine the maximum possible fuel consumption for that engine/heater/boiler as described in Condition 11.5a, or measure the actual daily fuel consumption for that engine/heater/boiler as described in Condition 11.5b. The Permittee may use Condition 11.5a for some units and Condition 11.5b for the other units, as long as the combined total daily fuel consumption for EU IDs 1 and 2 is either determined or measured. Make this determination for each well pad/drill site identified in the initial application, the subsequent annual notification submitted under Condition 21, or the most recent relocation notification submitted through Attachment 3, as applicable.
- a. Determine the maximum possible fuel consumption for a unit as follows:
 - (i) Determine the maximum hourly fuel consumption in gal/hr for the given unit from either vendor data, or a back-calculation from the rated capacity using standard engineering techniques and thermal efficiencies. Keep a copy of your determination and all supporting data, assumptions, and/or calculations, as required under Condition 16; and
 - (ii) Calculate the maximum daily fuel consumption for the unit by multiplying the maximum hourly fuel consumption determined under Condition 11.5a(i) by 24. Record the result, in units of gal/day.
 - b. Monitor and record the actual fuel consumption for a unit or a group of units as follows:
 - (i) Monitor the fuel consumption using one of the following methods:
 - (A) Install, maintain, and operate totaling fuel flow meters that are accurate to within ± 5 percent;
 - (B) Tank strapping;
 - (C) Delivery truck fuel dispensing meters;
 - (D) Runtime (hours) and full load fuel consumption rate in gal/hr provided by the manufacturer or back-calculation from the rated capacity using standard engineering techniques and thermal efficiencies; or
 - (E) Methods similar to those described in the Sample Fuel Consumption Monitoring Plan⁹ in Attachment 4.
 - (ii) Record the daily fuel consumption in gal/day using one or more of the following methods:
 - (A) Fuel flow meters – record the total amount of diesel fuel fired during the calendar day;
 - (B) Tank strapping;

⁹ The Permittee may develop a custom fuel monitoring and recordkeeping plan using the Sample Plan as guidance. This plan shall be submitted with the permit application and is subject to Department review. If the Department determines that the plan does not produce accurate and precise results, the Permittee shall adjust the plan to ensure accuracy and precision.

- (1) At a consistent time each day, record the diesel fuel height in the tank and the time of the reading.
 - (2) For each fuel delivery
 - i. Initial diesel fuel height;
 - ii. Final diesel fuel height;
 - iii. Tank identification; and
 - iv. Method of volume calculation (chart, site glass, mathematical equation, etc.).
 - (3) Maintain a copy of the manufacturer height to volume calculation chart on site for each tank;
- (C) Delivery truck fuel dispensing meters – record the diesel fuel dispensed to the units subject to Condition 11.5b during each calendar day;
- (D) Runtime and full load assumption:
- (1) Use a non-resettable hour meter to determine the runtime of the unit;
 - (2) For each day the unit operates, record at a consistent time each day, the daily hours of operation; and
 - (3) Calculate and record the daily fuel usage of the unit using the hours of operation recorded in Condition 11.5b(ii)(D)(2) and the manufacturer’s full load fuel consumption rate or back-calculation from the rated capacity using standard engineering techniques and thermal efficiencies.
- (E) Methods similar to those described in the Sample Fuel Consumption Monitoring Plan⁹ in Attachment 4.
- c. Record the total daily fuel consumption, in gal/day, as described below:
- (i) If solely using Condition 11.5a for determining the daily fuel consumption for all nonroad engines operated as EU ID 1 and all heaters/boilers operated as EU ID 2 during the reporting period, sum the maximum possible daily fuel consumptions determined under Condition 11.5a(ii) for each unit. Record the total maximum fuel consumption in gal/day.
 - (ii) If using Condition 11.5b for determining the actual daily fuel consumption for one or more nonroad engines operated as EU ID 1 or one or more heaters/boilers operated as EU ID 2 during the reporting period, do the following at the end of each calendar day for the previous day:
 - (A) Sum the total fuel consumed during the day by all units that are being tracked under Condition 11.5b;

- (B) If applicable, add the maximum possible daily fuel consumption determined under Condition 11.5a for the remaining units, to the sum determined under Condition 11.5c(ii)(A);
 - (C) Record, in gal/day, the value determined under Condition 11.5c(ii)(A) and if applicable, the value determined under Condition 11.5c(ii)(B).
- d. Report in each operating report required under Condition 19 one of the following for each well pad/drill site identified in the initial application, the subsequent annual notification submitted under Condition 21, or the most recent relocation notification required under Condition 22, as applicable:
 - (i) The maximum possible combined daily fuel consumption, in gal/day, of all nonroad engines operated as EU ID 1 and all heaters/boilers operated as EU ID 2 during the reporting period, as determined under Condition 11.5c(i);
 - (ii) The largest actual combined daily fuel consumption for the reporting period, in gal/day, of all nonroad engines operated as EU ID 1 and all heaters/boilers operated as EU ID 2, as determined under Condition 11.5c(ii);
 - (iii) In the event that records of the total daily fuel consumption are kept according to Condition 11.5c(i) and according to Condition 11.5c(ii), report the sum total of the maximum combined daily fuel consumption (gal/day) determined under Condition 11.5c(i) and the actual combined daily fuel consumption (gal/day) determined under Condition 11.5c(ii) for all nonroad engines operated as EU ID 1 and all heaters/boilers operated as EU ID 2 during the reporting period; or
 - (iv) That no POGO activity occurred at the given well pad/drill site during the reporting period.
- e. Report in each operating report required under Condition 19 the start and end dates that EU ID 1 and/or EU ID 2 operated concurrently with fracking.
- f. Report as described in Condition 17, anytime the daily combined fuel consumption limits for EU IDs 1 and 2 listed in Table 2 are exceeded (except as provided under the excursion limits listed in Condition 11.3), or if Condition 11 or its sub-conditions are not met.
- g. Upon request by the Department, demonstrate how the fuel consumption has been tracked/ estimated for all nonroad engines identified as EU ID 1 and/or all heaters and boilers identified as EU ID 2. These records may include but are not limited to:
 - (i) recorded data from fuel tracking devices or procedures;
 - (ii) calculations used to estimate fuel consumption based on operating time;
 - (iii) review of fuel tracking standards; and/or
 - (iv) inspection of the fueling operation and volume tracking.

12. SO₂ Ambient Air Quality Protection. To protect the 1-hour, 3-hour, 24-hour, and annual SO₂ AAAQS, the Permittee shall:

- 12.1 Combust only diesel fuel that meets the specifications of ultra-low sulfur diesel (ULSD) (i.e., maximum concentration of 0.0015 percent sulfur by weight) in each nonroad engine operated as EU ID 1.
- a. Monitor, record, and report as follows:
- (i) Obtain and keep certified receipts from the fuel suppliers that confirms that all diesel fuel combusted in the units listed in Condition 12.1 meets the specifications of ULSD.
 - (ii) Report in each operating report required by Condition 19, for the period covered by that report, a statement indicating whether all fuel combusted in the units listed in Condition 12.1 during the reporting period was ULSD.
 - (iii) Report as described in Condition 17 if any fuel combusted in the units listed in Condition 12.1 exceeds the sulfur content limit required by Condition 12.1.
- 12.2 Combust only diesel fuel that contains a sulfur content of 0.15 percent by weight or less in the heaters/boilers identified as EU ID 2.
- a. Monitor, record, and report as follows:
- (i) For diesel fuel delivered from a North Slope topping plant, obtain from the topping plant the results of a monthly fuel sulfur analysis.
 - (ii) For fuel delivered by third-party suppliers, obtain and keep certified receipts from fuel suppliers to document the sulfur content of the delivered fuel.
 - (iii) Include in the operating report required by Condition 19, for the period covered by that report, a copy of all records obtained under Conditions 12.2a(i) and 12.2a(ii).
 - (iv) Report as required under Condition 17 if any fuel combusted in EU ID 2 exceeds the fuel sulfur content limit required by Condition 12.2.

Section 6 *Recordkeeping, Reporting, and Certification Requirements*

- 13. 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 emissions 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.
- 13.1 The Department may accept an electronic signature on an electronic application or other electronic record required by the Department if the person providing the electronic signature
- a. uses a security procedure, as defined in AS 09.80.190, that the Department has approved; and
 - b. accepts or agrees to be bound by an electronic record executed or adopted with that signature.
- 14. Submittals.** Unless otherwise directed by the Department or this permit, the Permittee shall submit to the Department one certified copy of reports, compliance certifications, and/or other submittals required by this permit. The Permittee may submit the documents electronically or by hard copy.
- 14.1 Submit the certified copy of reports, compliance certifications, and/or other submittals in accordance with the submission instructions on the Department’s Standard Permit Conditions web page at <http://dec.alaska.gov/air/air-permit/standard-conditions/standard-condition-xvii-submission-instructions/>.
- 15. 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, 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.
- 16. Recordkeeping Requirements.** The Permittee shall keep all records required by this permit for at least five years after the date of collection, including:
- 16.1 copies of all reports and certifications submitted pursuant to this section of the permit.
 - 16.2 records of all monitoring required by this permit, and information about the monitoring including (if applicable):
 - a. calibration and maintenance records, original strip chart or computer-based recordings for continuous monitoring instrumentation;
 - b. sampling dates and times of sampling or measurements;
 - c. the operating conditions that existed at the time of sampling or measurement;

- d. the date analyses were performed;
- e. the location where samples were taken;
- f. the company or entity that performed the sampling and analyses;
- g. the analytical techniques or methods used in the analyses; and
- h. the results of the analyses.

17. Excess Emissions and Permit Deviation Reports. The Permittee shall report excess emissions and permit deviations as follows:

17.1 Excess Emissions Reporting. The Permittee shall report all emissions or operations that exceed emissions standards or limits of this permit as follows:

- a. In accordance with 18 AAC 50.240(c), as soon as possible after the event commenced or is discovered, report
 - (i) excess 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 caused emissions in excess of a technology based emissions standard;
- c. If a continuous or recurring excess emissions is not corrected within 48 hours of discovery, report within 72 hours of discovery unless the Department provides written permission to report under Condition 17.1d.
- d. Report all other excess emissions not described in Conditions 17.1a, 17.1b, and 17.1c within 30 days after the end of the month during which the excess emissions occurred or as part of the next routine operating report in Condition 19 for excess emissions that occurred during the period covered by the report, whichever is sooner.
- e. If requested by the Department, the Permittee shall provide a more detailed written report to follow up on an excess emissions report.

17.2 Permit Deviations Reporting. For permit deviations that are not “excess emissions,” as defined under 18 AAC 50.990:

- a. Report all permit deviations within 30 days after the end of the month during which the deviation occurred or as part of the next routine operating report in Condition 19 for permit deviations that occurred during the period covered by the report, whichever is sooner.

17.3 Notification Form. When reporting either excess emissions or permit deviations, the Permittee shall report using either the Department’s online form, which can be found at the Division of Air Quality’s Air Online Services (AOS) system webpage <http://dec.alaska.gov/applications/air/airtoolsweb> using the Permittee Portal option, or, if

the Permittee prefers, the form contained in Attachment 5 of this permit. The Permittee must provide all information called for by the form that is used. Submit the report in accordance with the submission instructions on the Department's Standard Permit Conditions webpage found at <http://dec.alaska.gov/air/air-permit/standard-conditions/standard-conditions-iii-and-iv-submission-instructions/>.

- 18. Triennial Emission Inventory Reporting.** Every third year by April 30, the Permittee shall submit to the Department reports of actual emissions for the previous calendar year, by emissions unit, of CO, NH₃, NO_x, PM₁₀, PM_{2.5}, SO₂, VOC, lead (Pb), and lead compounds, as follows:
- 18.1 For reporting under Condition 18, the Permittee shall report the annual emissions and the required data elements under Condition 18.3 every third year for the previous year as scheduled by the EPA.¹⁰
- 18.2 For the purposes of reporting actual or assessable emissions required under Condition 18 and Condition 4.4, respectively, the Permittee shall use consistent pollutant-specific emission factors and calculation methods for all reporting requirements for the stationary source.
- 18.3 For each emissions unit and the stationary source, include in the report the required data elements¹¹ contained within the form included in the Emission Inventory Instructions available at the Department's AOS system on the Point Source Emission Inventory webpage at <http://dec.alaska.gov/Applications/Air/airtoolsweb/PointSourceEmissionInventory>.
- 18.4 Submit the report in accordance with the submission instructions on the Department's Standard Permit Conditions webpage at <http://dec.alaska.gov/air/air-permit/standard-conditions/standard-conditions-xv-and-xvi-submission-instructions/>.
- 19. Operating Reports.** During the life of the permit, the Permittee shall submit to the Department an operating report in accordance with Conditions 13 and 14 by August 15 for the period January 1 through June 30 of the current year and by February 15 for the period July 1 through December 31 of the previous year.
- 19.1 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.
- 19.2 When excess emissions or permit deviations that occurred during the reporting period are not reported under Condition 19.1, the Permittee shall identify
- the date of the excess emissions or permit deviation;
 - the equipment involved;

¹⁰ The calendar years for which reports are required are based on the triennial reporting schedule in 40 C.F.R. 51.30(b)(1), which requires states to report emissions data to the EPA for inventory years 2014, 2017, 2020, 2023 and every 3rd year thereafter. Therefore, the Department requires Permittees to report emissions data for the same inventory years by April 30 of the following year (e.g., triennial emission inventory report for 2020 is due April 30, 2021, triennial emission inventory report for 2023 is due April 30, 2024, etc.).

¹¹ The required data elements to be reported to the EPA are outlined in 40 C.F.R. 51.15 and Tables 2a and 2b to Appendix A of 40 C.F.R. 51 Subpart A.

- c. the permit condition affected;
- d. a description of the excess emissions or permit deviation; and
- e. any corrective action or preventative measures taken and the date(s) of such actions;
or

19.3 When excess emissions or permit deviation reports have already been reported under Condition 17 during the period covered by the operating report, the Permittee shall either

- a. include a copy of those excess emissions or permit deviation reports with the operating report; or
- b. cite the date(s) of those reports.

- 20. Annual Affirmation of Qualification.** The Permittee shall submit to the Department by March 31 of each year, an affirmation certified according to Condition 13 of whether the POGOs operating under the MG2 Rev. 1 Permit still qualify for this permit and that Title V permitting will not be triggered by the POGO activities.
- 21. Annual Notification.** The Permittee shall submit to the Department by December 31st of each year, their MG2 Rev. 1 POGO plans for the following calendar year. The Permittee shall do so by completing and submitting the form in Attachment 2. The Permittee may submit one annual notification per Unit.¹²
- 22. Relocation Notification.** The Permittee shall notify the Department if there is a revision to the well pads/drill sites identified in the initial application or annual notification submitted under Condition 21 as soon as possible, prior to operating at the new well pad/drill site. Use the form in Attachment 3 to make this notification.

¹² Units are identified by the Alaska Department of Natural Resources Division of Oil and Gas on state land and by the Bureau of Land Management on federal lands.

Section 7 *Standard Permit Conditions*

- 23.** 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
- 23.1 an enforcement action; or
 - 23.2 permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280.
- 24.** 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.
- 25.** 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.
- 26.** 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.
- 27.** The permit does not convey any property rights of any sort, nor any exclusive privilege.
- 28.** 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
- 28.1 enter upon the premises where an emissions unit subject to this permit is located or where records required by the permit are kept;
 - 28.2 have access to and copy any records required by this permit;
 - 28.3 inspect any stationary source, equipment, practices, or operations regulated by or referenced in the permit; and
 - 28.4 sample or monitor substances or parameters to assure compliance with the permit or other applicable requirements.

Section 8 ***General Source Test Requirements***

- 29. Requested Source Tests.** In addition to any source testing explicitly required by this permit, the Permittee shall conduct source testing as requested by the Department to determine compliance with applicable permit requirements.
- 30. Operating Conditions.** Unless otherwise specified by an applicable requirement or test method, the Permittee shall conduct source testing
- 30.1 at a point or points that characterize the actual discharge into the ambient air; and
 - 30.2 at the maximum rated burning or operating capacity of the source or another rate determined by the Department to characterize the actual discharge into the ambient air.
- 31. Reference Test Methods.** The Permittee shall use the following references for test methods when conducting source testing for compliance with this permit:
- 31.1 Source testing for the reduction in visibility through the exhaust effluent must be conducted in accordance with the procedures set out in 40 C.F.R. 60, Appendix A, Reference Method 9. The Permittee may use the form in Attachment 1 of this permit to record data.
 - 31.2 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.
 - 31.3 Source testing for emissions of PM-10 and PM-2.5 must be conducted in accordance with the procedures specified in 40 C.F.R. 51, Appendix M, Methods 201 or 201A and 202.
 - 31.4 Source testing for emissions of any contaminant may be determined using an alternative method approved by the Department in accordance with 40 C.F.R. 63 Appendix A, Method 301.
- 32. 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.
- 33. Test Plans.** 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 test plan within 60 days after receiving a request under Condition 29 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.
- 34. Test Notification.** At least 10 days before conducting a source test, the Permittee shall give the Department written notice of the date and time the source test will begin.
- 35. Test Reports.** 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 as set out in Condition 13. If requested in writing by the Department, the Permittee must provide preliminary results in a shorter period of time specified by the Department

Attachment 1 – Visible Emissions Form

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 VE 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 clinometer.
- 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, is Plume...: check “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 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.
- Organization: observer’s employer.
- Certified By, Date: name of “smoke school” certifying observer and date of most recent certification.

Attachment 2 – Annual Notification Form

**ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY CONTROL MINOR GENERAL PERMIT**

**MINOR GENERAL PERMIT 2 (MG2) Revision 1
FOR PORTABLE OIL AND GAS OPERATIONS (POGO)**

Annual Notification Form for Calendar Year 20__

--

Company Name

Oil and Gas Unit(s) or Well Pad(s)

Drilling Rig(s) Identification

Equipment to Operate during Calendar Year 20_____

Permit No.: AQ_____MG2____ Rev. 1

Select the appropriate check boxes in the table below, identifying the POGO equipment that is planned to operate during calendar year 20_____.

EU ID	Planned Operation	EU Name	EU Description	Total Rating/Size
1	<input type="checkbox"/> Yes <input type="checkbox"/> No	Drill Rig Reciprocating Engines	Diesel-fired Nonroad Engines	Varies
2	<input type="checkbox"/> Yes <input type="checkbox"/> No	Drill Rig Heaters and Boilers	Diesel-fired Heaters and Boilers	Varies
3	<input type="checkbox"/> Yes <input type="checkbox"/> No	Well Venting/Flow Backs	N/A	Varies
4	<input type="checkbox"/> Yes <input type="checkbox"/> No	Miscellaneous POGO Reciprocating Engines Not On Drill Rig	Diesel-fired Nonroad Engines	Varies
5	<input type="checkbox"/> Yes <input type="checkbox"/> No	Miscellaneous POGO Heaters and Boilers Not On Drill Rig	Diesel-fired Heaters and Boilers	Varies
6	<input type="checkbox"/> Yes <input type="checkbox"/> No	POGO Portable Flares	Fuel Gas	Varies

**CERTIFICATION
FOR
MINOR PERMITS**

18 AAC 50.205 Certification. Any permit application, report, affirmation, or compliance certification required by the department under a permit program established under AS 46.14 must include the signature of a responsible official for the permitted stationary source.

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.

Signature

Printed Name

Title

Attachment 3 – Relocation Notification

Submit the following information to the Department as soon as possible *before* moving the POGO to a well pad/drill site not previously identified in the initial application or annual notification form.

Facility Information:

Permittee Name: _____ Permit: AQ _____

Rig Name(s): _____

Unit Name (if applicable): _____

Well Pad(s) / Drill Site(s): _____

Operator Name: _____

Contact Person: _____ Telephone: _____

Estimated Operating Dates:

Estimated start-up date: _____

Estimated shut-down date: _____

Location Information:

New Rig Location(s):

(Specify latitude and longitude to at least four decimal degrees.)

Latitude _____ Longitude _____

Latitude _____ Longitude _____

Latitude _____ Longitude _____

Comments: _____

Printed Name: _____ Title: _____ Date: _____

Signature: _____ Phone Number: _____

Submit completed report in accordance with the submission instructions on the Department’s Standard Permit Conditions web page at <http://dec.alaska.gov/air/air-permit/standard-conditions/standard-condition-xvii-submission-instructions/>.

Attachment 4 – Sample Fuel Consumption Monitoring Plan

Sample Fuel Consumption Monitoring Plan

Purpose: To monitor and record daily fuel consumed in rig diesel-fired equipment.

Scope: This Plan covers drilling rigs’ emissions units powered with diesel fuel. It does not cover fuel consumed by individual vehicles or ancillary equipment.

Roles and Responsibilities

Role	Responsibilities
Toolpusher	<p>Daily</p> <p>Ensure all diesel-fired equipment has one of the following methods in place to track daily fuel usage:</p> <ol style="list-style-type: none"> 1. Metering; 2. Tank strapping; or 3. Operational hours tracking <p>Fuel Delivery Tracking</p> <p>Ensure all fuel usage is tracked on the “daily fuel usage report”</p> <p>Ensure this plan is understood and carried out by operating personnel.</p> <p>Be knowledgeable of current permit requirements pertaining to fuel consumption monitoring and recording.</p> <p>Assign competent personnel to record consumed fuel of stipulated diesel fired equipment.</p> <p>Ensure correct and consistent fuel consumption monitoring and recording.</p> <p>Keep fuel use logs on location.</p> <p>Submit reports as requested to the Company Representative</p> <p>Review recording process with assigned personnel periodically.</p> <p>Use Management of Change process for all design, usage or process modifications involving diesel fired equipment.</p>
Assigned Personnel	<p>Be knowledgeable of current permit requirements pertaining to fuel consumption monitoring and recording.</p> <p>Be knowledgeable and competent to perform task of recording daily operational hours and consumed fuel of all diesel fired equipment.</p> <p>Keep accurate records.</p> <p>Immediately report any failure of measurement devices.</p>
HSE Manager	<p>Develop and Maintain Fuel Consumption Procedure</p> <p>Assist in monitoring and communicating fuel usage to Operators</p> <p>Respond to questions and concerns from Field Personnel</p>
HSE Administrative Assistant	<p>Receive Daily Fuel Use Logs</p> <p>Maintain Fuel Use Logs</p> <p>Prepare quarterly a table of daily fuel use by rig and transmit this to Company Environmental Coordinator</p>

Procedure/Requirements

1. Assigned Personnel shall monitor daily drill rig fuel use in all rig engines, heaters, and boilers using the methods below and will provide the HSE Administrative Assistant the daily fuel usage reports at the end of each month.
2. Fuel usage monitoring and recordkeeping (if using equipment fuel flow meters)
 - a. Record on daily fuel usage report the equipment fuel flow meter reading and the time reading was taken.
 - b. Calculate and record on the daily fuel usage report daily fuel use by subtracting previous day's meter reading from today's.
3. Fuel usage monitoring and recordkeeping (if strapping)
 - a. For each tank being strapped, record on daily fuel usage report the fuel height and time of daily reading.
 - b. On days where fuel is delivered into the tank, record the height on the daily fuel log before the delivery and after the delivery with a note that these additional heights are recorded due to a fuel delivery. The fuel consumption for that day may be determined using the pre-delivery height reading or by taking and recording one at the end of the day. Thus, for the following day use the post-delivery height reading or the end of the day height reading as appropriate.
 - c. Document the method of volume calculation from height in inches to gallons (conversion chart, site glass, calculation), keep the conversion chart on location.
4. Fuel usage monitoring and recordkeeping where daily deliveries are made to rig tank(s)
 - a. If the deliveries are metered, record metered volume on daily fuel usage report. This is the amount assumed to be consumed by rig equipment.
 - b. If the deliveries are not metered, record initial and final fuel height readings in the receiving tank(s) and use this to calculate the volume delivered. Record this on the daily fuel usage report as the amount assumed to be consumed.
 - c. Generally, tanks should be filled to a similar level each day.
5. Fuel usage monitoring and recordkeeping (no metering or strapping)
 - a. Ensure affected equipment has a non-resettable hour meter installed
 - b. Using Excel, for each piece of equipment on the rig, create a table with columns labeled Date, Time, Equipment Maximum Fuel Consumption Rate Per Hour, Hours Operated, Fuel Consumed (maximum fuel consumption rate per hour x hours operated). Each row on the table will be a separate calendar day. Use separate tabs for each piece of equipment; label the tabs with the equipment ID
 - c. Create a summary tab that contains a table with rows representing each day. Label the first column Date and the second column Total Rig Fuel Consumed. Set up each cell in the second column to sum the daily Fuel Consumed from each individual equipment tab.
6. HSE Administrative Assistant will transmit to Company Environmental Coordinator within one week of the end of each calendar quarter a table of daily rig fuel consumption over that calendar quarter.

Attachment 5 – Excess Emissions and Permit Deviation Notification Form¹³

Excess Emissions and Permit Deviation Reporting
State of Alaska Department of Environmental Conservation
Division of Air Quality

Stationary Source Name

Air Quality Permit No.

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

Note: All “excess emissions” are also “permit deviations.” However, use only Section 1 for events that involve excess emissions.

Deviation from Permit Conditions - Complete Section 2 and Certify

Note: Use only Section 2 for permit deviations that do not involve excess emissions.

Deviation from COBC¹⁴, CO¹⁵, or Settlement Agreement - Complete Section 2 and Certify

¹³ Revised as of July 22, 2020.

¹⁴ Compliance Order By Consent

¹⁵ Compliance Order

Section 1. Excess Emissions

(a) **Was the exceedance** Intermittent or Continuous

(b) **Cause of Event** (Check one that applies. Complete a separate form for each event, as applicable.):

- | | |
|--|--|
| <input type="checkbox"/> Start Up/Shut Down | <input type="checkbox"/> Natural Cause (weather/earthquake/flood) |
| <input type="checkbox"/> Control Equipment Failure | <input type="checkbox"/> Scheduled Maintenance/Equipment Adjustments |
| <input type="checkbox"/> Bad fuel/coal/gas | <input type="checkbox"/> Upset Condition |
| <input type="checkbox"/> Other _____ | |

(c) **Description**

Describe briefly what happened and the cause. Include the parameters/operating conditions exceeded, limits, monitoring data and exceedance. Attach supporting information if necessary.

(d) **Emissions Units (EU) Involved:**

Identify the emissions units 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 all that apply and provide the value requested, if any):

- | | |
|---|---|
| <input type="checkbox"/> Opacity _____% | <input type="checkbox"/> Venting _____(gas/scf) |
| <input type="checkbox"/> Control Equipment Down | <input type="checkbox"/> Fugitive Emissions |

Emission Limit Exceeded

Marine Vessel Opacity

Flaring

Other: _____

(f) Corrective Actions:

Describe actions taken to restore the system to normal operation and to minimize or eliminate chances of a recurrence. Attach supporting information if necessary.

(g) 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 all boxes that apply per event. Complete a separate form for each event, as applicable.)

- Emissions Unit-Specific Requirements
- Stationary Source-Wide Specific Requirements
- Monitoring/Recordkeeping/Reporting Requirements
- General Source Test Requirements
- Compliance Certification Requirements
- Standard/Generally Applicable Requirements
- Insignificant Emissions Unit Requirements
- Other: _____

(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 condition 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. Attach supporting information if necessary.

(d) Corrective Actions:

Describe actions taken to correct the deviation or potential deviation and to prevent future recurrence. Attach supporting information if necessary.

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). Read and sign the certification in the bottom of the form above. (See Condition 13.) Submit this report in accordance with the submission instructions on the Department’s Standard Permit Conditions web page at <http://dec.alaska.gov/air/air-permit/standard-conditions/standard-conditions-iii-and-iv-submission-instructions/>. If submitted online, report must be submitted by an authorized E-signer for the stationary source (according to Condition 13).*