**Alaska Department of Environmental Conservation**
**Air Permits Program**

**BP Exploration (Alaska) Inc.**
**Gathering Center #1 (GC#1)**

# STATEMENT OF BASIS
**of the terms and conditions for**
**Permit No. AQ0182TVP02**

**Public Comment - April 19, 2012**

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# INTRODUCTION

This document sets forth the statement of basis for the terms and conditions of Operating Permit No. AQ0182TVP02.

## GATHERING CENTER #1
## STATIONARY SOURCE IDENTIFICATION

Decision

Gathering Center #1 (GC#1) is located within the Prudhoe Bay Unit (PBU) on the North Slope of Alaska. The Department has determined the GC#1 stationary source is the surface structures with their associated emission units located on the GC#1 production pad and emissions units located on PBU well pads D, E, F, G, K, Y, and P. This determination applies to both the State's Title I and Title V air quality permitting programs.

The significant emission units on these pads for Title V purposes are those identified in Table A of Operating Permit No. AQ0182TVP02. Additional insignificant emission units are located on the GC#1 production pad and the well pads, for instance the drill site manifold and wellhead enclosures are considered insignificant emission units in accordance with state regulation 18 AAC 50.326(f)(93).

Drill rigs and other temporary emission units will periodically operate at the well pads. Operation of such emission units will be considered temporary activities as long as they are not located and operated (continuously or intermittently) at the same well pad for more than 24 consecutive months. The 24-month clock is reset each time these emission units are moved from well pad to well pad, even if the new physical location is at a well pad governed by the same permit as the previous well pad location.

Discussion

In reaching this decision the Department relied on the definition of stationary source and the concept of common sense notion of plant as discussed in the preamble to the Federal PSD regulations, 45 Fed. Reg. 52693.

The following Federal definitions from 40 C.F.R. §51.166(b) have been adopted by the State statute and are relevant to this discussion.

- *Stationary source* means any building, structure, facility, or installation, which emits or may emit a regulated NSR pollutant.
- *Building, structure, facility, or installation* means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control)…. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same *Major Group* (i.e., which have the same two-digit code) as described in the *Standard Industrial classification Manual, 1972*….
- *Emission unit* means any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant….

Based on these definitions, the pollutant-emitting activities must meet three criteria to be included in the stationary source:

1) They must "belong to the same industrial grouping" as described by their SIC code. On the North Slope all the oilfield facilities have the same SIC code (1311 - Crude Petroleum and Natural Gas Production).
2) They must be "located on one or more contiguous or adjacent properties". This is a location based physical proximity requirement, as discussed in the preamble to the Federal PSD regulations, 45 Fed. Reg. 52676.
3) They must be "under the control of the same person". Within the PBU, BP Exploration (Alaska) Inc. (BPXA) is the operator and implements the decisions of the leaseholders via the Unit Operating Agreement.

Since items #1 and #3 above are self-evident no further discussion is needed.

Item #2 is the proximity criterion. To determine if the "property" or "properties" are located in close proximity, the relevant "property" must first be identified. The ADEC has determined that within the North Slope oilfields "property" is considered to be the improved surface areas (pads) because: 1) oil and gas production activities occur over vast areas in which there is limited surface disturbance, 2) land use permits must be obtained from the state for any surface disturbances, 3) the unique permafrost environment limits the extent of any surface disturbances, and 4) the pollutant emitting activities are located on the pads.

The PBU production centers and production wells are located on separate pads that are not contiguous (i.e., not touching). Thus the adjacency (i.e., the nearness or closeness) must be evaluated. To evaluate the adjacency of facilities, ADEC has used the concept of the common sense notion of a plant to inform proximity. In its analysis, ADEC has developed what is referred to as the "wagon wheel" model based on the production centers (hubs) and well pads (spokes). In this model of the plant, the well pads deliver raw materials (wellhead fluids consisting of crude oil, water, and hydrocarbon gases) to the production center for processing into finished product (sales oil) for delivery and custody transfer at Pump Station #1 of the Alyeska Pipeline Service Company.

The wagon wheel model for determining the stationary source for PSD and Title V applicability is currently used at other operating units on the North Slope such as Lisburne, Endicott, Kuparuk, and Alpine. The physical proximity (miles) varies widely at these sources and ADEC does not propose to establish a fixed value for this parameter. For instance, the longest spoke at Lisburne is drill site DS-L5, which is 6 miles from the production center (hub), at Endicott is drill site SDI, which is 3 miles from the production center (hub), at Kuparuk is drill site 3R, which is 3 miles from the CPF-3 production center (hub), and at Alpine is drill site DS2, which is 3 miles from the production center (hub). Within the PBU, Z-Pad is 9 miles from the GC#2 production center (hub), and for the GC#1 stationary source Y-Pad is 4 miles from the production center (hub).

Which spokes will be attached to which hubs are, of course, determined by the flow of wellhead fluids (raw materials) and sales oil (finished crude). Whether a production well pad is part of a larger stationary source centered at a production center (hub) will be determined on a case-by-case basis taking into consideration site-specific factors such as the common sense notion of a plant, air impact overlaps/airshed, predictable emission impacts on hub, different operating units/control, service contracts with other operating units, ease of permit administration, and other case-specific factors deemed relevant. For instance, for a new unitized development the presumptive maximum radius of the spokes would be based on the original development project. Under the wagon wheel model, the associated infrastructure is considered a separate stationary source, unless co-located on the same pad or primarily associated with a hub or another stationary source.

Rationale for Hub and Spoke Aggregation Model

In the context of the PBU, the relevant units of property are the pads on which the sources are situated, as distinguished from the surrounding tundra. Guidance developed by the State of Texas (Definition of Site, March 2002) for determining stationary sources located within producing oilfields states "For leased properties, 'property' is considered the surface area on which a stationary source has been placed, including any immediate area graded or cleared for stationary sources."

Why consider the production centers (hubs) along with their associated production well pads (spokes) as the basic stationary source or production plant for the PBU?

1) *Proximity.* The primary function of the production centers at the PBU (GC#1, GC#2, GC#3, FS#1, FS#2, FS#3, and Lisburne) is separation and processing of three-phase well fluids (oil, gas, and water) into sales-quality crude oil for delivery to the Trans-Alaska Pipeline System at Pump Station #1. Each production center is capable of performing this function independently of the other production centers. For example, if FS#2 were shutdown for maintenance, FS#1, FS#3, GC#1, GC#2, GC#3, and Lisburne would continue to process oil, gas, and water without adverse impact. Grouping the well pads with their respective production centers maintains the important role of proximity in aggregation decisions.

2) *Common Sense Notion of Plant.* In the preamble to the PSD regulations of 1980 EPA (45 Fed. Reg. 52693) emphasized the importance of a "common sense" notion of source for the PSD program as follows:

   *In EPA's view, the December opinion of the court in* Alabama Power *sets the following boundaries on the definition for PSD purposes of the component terms of "source"; 1) it must carry out reasonably the purposes of PSD, 2) it must approximate a common sense notion of "plant", and 3) it must avoid aggregating pollutant-emitting activities that as a group would not fit within the ordinary meaning of "building," "structure," "facility," or "installation."*

Due to the nature of the oil and gas extraction business, facilities must be scattered across the resource area creating duplicate facilities performing identical functions. Well production pads must be dispersed evenly across the unit so that all the leases can be accessed. Likewise, production centers must be scattered since they act as collection points of the raw materials brought to the surface at the well pads. The hub and spoke production model develops naturally from the logistics of the business.

Within this conceptual framework, ADEC determines the plant to be the well production pads that extract the raw materials (wellhead fluids) from the subsurface and deliver them to the factory (production center) for processing into finished product (crude oil for sales) and waste products (water and gas for underground disposal). Wellhead facilities and separation facilities cannot exist without each other and constitute a complete production plant.

3) *Reasonable Permit Administration.* This approach allows ADEC more feasible permit administration with comparable environmental benefits. The benefit of going beyond the reasonably scaled wagon wheel approach for evaluating emission effects on other facilities is not apparent. Finally, previous permitting actions by ADEC at Kuparuk, Lisburne, Endicott, and Alpine support the determined stationary sources using the hub and spoke model. The facilities within the PBU would then be treated the same as these other operating units.

<u>Other Models of Aggregation Discussed</u>

There were two other questions considered to determine the appropriate stationary sources for permitting purposes at the PBU. First, should the entire PBU be the stationary source? Second, should each individual pad with its emitting units be considered a separate stationary source? Both of these potential permitting approaches were evaluated and rejected for reasons discussed below and the wagon wheel approach was accepted as being reasonable decision making.

1) *Prudhoe Bay Unit ≠ Stationary Source*. The PBU is made up of the oil leases that overlie the Prudhoe Bay Permian-Triassic Reservoir and covers roughly 300 square miles. To consider all the facilities located therein as a single stationary source severely stretches the concept of proximity. The ADEC does not believe that the leases and operating units constructed from these leases is the proper focus of a regulatory program concerned with air emissions. The leases and unit agreement pertain to subsurface development and long-term reservoir management to maximize economic gain for the leaseholders and lessor. If the Prudhoe Bay operating unit were to be determined the relevant source for aggregation, then there is no logical reason to stop at the boundaries of the PBU since contiguous operating units (i.e. Lisburne, Endicott, Milne, Northstar, and Pt. McIntyre) are also under the common control of BPXA.

Should pipeline connections be used to determine the appropriate stationary source? The ADEC does not believe this is a deciding factor because in the oil and gas industry pipelines connect everything. Pipelines are used throughout the operating unit as the preferred method for transferring fluids between facilities. To only consider the connectivity of operations via pipelines to determine proximity and to not also consider the concept of a common sense notion of a plant would result in one stationary source extending from the North Slope oil fields all the way to the Valdez Marine Terminal.

The complexity of administering (government) and operating (industry) a stationary source as large as the PBU without clear corresponding environmental benefit argues against this approach. Some of the identified problems are:

a) Netting analyses conducted over such a large stationary source could lead to avoiding all PSD reviews.

b) De-bottlenecking analyses would be more difficult; judgment calls about how far out from the equipment modification would become more complicated.

c) Tracking cause and effect of activities within the unit would be difficult; calculation of associated emission effects would become more complicated.

d) Permit maintenance burden would be greater; both Title I and Title V permits would be in a constant state of revision.

e) Scope of review and analysis could discourage discrete facility upgrades. If ADEC were required to evaluate all air-related issues across the entire PBU at the same time, agency resources could be overwhelmed resulting in permitting delays.

Finally, there is no precedent for defining such a large stationary source, either the size of the PBU, the size of the contiguous North Slope oil fields operated by BPXA, or the size of all the current and future North Slope facilities and the transportation corridor to the deep water port of Valdez.

2) *Individual Pad ≠ Stationary Source*. Treating each individual pad and the emission units located on it as a stationary source is the current permitting practice for PBU. This practice does not conform to the court decision in the Alabama Power case concerning the definition of source and its component terms for PSD purposes.

a) *It must carry out reasonably the purposes of PSD*. Permitting individual sources does not adequately serve the purposes of PSD when major projects that contribute to the production process and emissions can be located on well pads but avoid PSD review. The primary purpose of PSD review being to maintain air quality within the applicable increments.

b) *It must approximate a common sense notion of plant*. The complete production process defining the plant that starts at the wellhead and ends at the sales oil line outlet from the production center is ignored.

c) *It must avoid aggregating pollutant-emitting activities that as a group would not fit within the ordinary meaning of "building", "structure", "facility", or "installation"*. Permitting individual pollutant-emitting activities does completely avoid aggregating those activities that do not fit the ordinary meaning of "facility".

Finally, using the wagon wheel approach for determining the appropriate stationary sources at PBU will ensure permitting consistency with the other operating units on the North Slope.

Status of Support Facilities at PBU

The services that support facilities provide (e.g., Seawater Treatment Plant, Grind & Inject, Base Operations Center, Central Power Station, etc.) are spread over the entire PBU (with six hubs) and other operating units such as Kuparuk, Lisburne, and Endicott with no one hub receiving a majority of the support provided. When these services have been co-located on a pad with another stationary source, they have been aggregated as in the case of the Crude Oil Topping Unit with PBOC/MCC and the Seawater Injection Plant West with GC#1. The purposes the support facilities serve are secondary to the function of the production hubs. In addition, some of the support facilities (Base Operations Center, Central Power Station, and Prudhoe Bay Operations Center/Main Construction Camp) only exist because of the remote location of the North Slope oilfields and are not inherent to oil and gas production. The service infrastructure has different purposes and, therefore, these activities are considered separate stationary sources.

The ADEC does propose combining two of the separate support facilities as part of this review of stationary sources operating at PBU. The ADEC has determined the Central Gas Facility (CGF) and the Central Compressor Plant (CCP) to be a single stationary source (the Gas Plant) for purpose of Title I and Title V permitting for the following reasons:

1) Physical proximity - the two facilities are located ¼ of a mile from each other.
2) Common sense notion of a plant - these two facilities constitute the gas handling plant. The raw material (low pressure high molecular weight gas) is delivered to CGF from the hubs for removal of miscible inject/natural gas liquids and pressurization (to intermediate pressure) for distribution, the vast majority of which is delivered to the Central Compressor Plant for additional pressurization. This final product (high pressure low molecular weight gas) is then distributed to injection wells nearby CCP for ultimate disposal/storage underground.
3) These two facilities were originally permitted as a single stationary source but were disaggregated during the late 1980s.

Satellite Field Development

In the context of the North Slope, satellite oilfields are usually small oil reservoirs located near the established oilfields and may be economically developed in the future using excess capacity at the existing production centers. Although at this time there are no satellite oilfields delivering wellhead fluids to any PBU production centers, there may be some in the future. Whether these facilities will become part of an existing stationary source such as GC#1 will be evaluated on a case-by-case basis using the wagon wheel model discussed in this document with primary focus on proximity and the common sense notion of a plant.

Current examples of satellite fields are Tarn and Meltwater located to the west of Kuparuk (15 and 25 miles respectively) that deliver wellhead fluids to Central Production Facility #2 (CPF#2) for processing into sales oil. In this case, emitting units at Tarn and Meltwater have not been added to the CPF#2 stationary source but were determined to be separate sources primarily based on proximity.

To encourage use of existing emission units at production hubs rather than the construction of additional emission units at satellite developments, production well pads created after the issuance of this permit will be evaluated on a case-by-case basis as follows.

1) Production well pads and their emission units that lie within the original development project surface area are presumed to be part of the existing hub stationary source to which they deliver well fluids unless compelling reasons justify their exclusion.
2) Production well pads and their emission units that lie outside the original development project surface area are presumed NOT to be part of the existing hub stationary source to which they deliver well fluids unless compelling reasons justify their inclusion.
3) For existing stationary sources, such as Alpine, Endicott, Northstar, and Badami that do not have an established original development project surface area because they consist of only one or two production well pads other factors will need to be considered when determining whether the well pad and its emission unit should become part of the existing stationary source.

Gathering Center #1 (GC#1) Description

Section 1 of Operating Permit No. AQ0182TVP02 contains information on the stationary source, as provided in the Title V permit application.

The stationary source (i.e., the Gathering Center #1 (GC#1) ) is operated by BP Exploration (Alaska) Inc., and BP Exploration (Alaska) Inc. is the Permittee for the stationary source's operating permit. The SIC code for this stationary source and alternative operating scenario is 1311 -- Crude Oil and Natural Gas Production. The NAICS code of this stationary source is 211111.

BPXA's GC#1 is an existing oil and gas production stationary source which consists of two GE Frame 5 natural gas-fired combustion turbines, four Cooper Rolls RB211 natural gas-fired combustion turbines (two of which are out of service), two Sulzer S3 natural gas-fired combustion turbines, three Ruston TA2500 natural gas-fired combustion turbines (each of which is out of service), two Econotherm natural gas-fired heaters, four Cleaver Brooks natural gas-fired heaters, two BS&B natural gas-fired triethylene glycol regenerators, one Smith natural gas-fired triethylene glycol regeneration reboiler, two 550 kW Caterpillar liquid fuel-fired emergency electric generators, one 550 kW Detroit Diesel liquid fuel-fired emergency electric generator, one 280 Hp Detroit Diesel liquid fuel-fired emergency firewater pump, one 2685 kW Detroit Diesel liquid fuel-fired emergency electric generator, one Allison 5000 Hp emergency liquid fuel-fired combustion turbine, six vertical flares, and two horizontal flares. The Well Pads D, E, F, G, K, Y, and P are currently included in the major stationary source called GC#1 although at this time no significant emission units are located on these pads.

GC#1 processes crude oil production fluids received from various crude oil accumulations located on the North Slope of Alaska, including (but not limited to) Well Pads D, E, F, G, K, Y, P, and various pads from Gathering Centers #2 and #3 of the Western Operating Area. GC#1 can process more than 300,000 barrels of crude oil per day and 2.5 billion standard cubic feet of gas. The production fluids consist mainly of crude oil, hydrocarbon gas, and water. The crude oil is processed to remove hydrocarbon gas and water in order to meet specific crude oil specifications prior to transporting via the Trans Alaska Pipeline to Valdez, Alaska. The hydrocarbon gas is dehydrated and compressed for reinjection into the reservoir or used as fuel. Water is processed to remove entrained crude oil before injection into disposal or injector wells.

The energy required to support operations comes primarily from the combustion of produced hydrocarbon gas that also supplies the Central Power Station.

Production/Injection wells are typically grouped together on a gravel pad with their well chokes and well testing equipment enclosed in modules. This collection of equipment on the gravel pad is called a well pad. Production fluids from these wells are often commingled into common carrying lines at these wells that then flow to GC#1 for processing. Additionally, fluids (seawater, produced water, enhanced oil recovery fluids, etc.) can be routed to the wells for diversion into injection wells. As the need arises, mobile equipment, i.e. drilling rigs, are used at the well pad to either service an existing well or drill a new well. This equipment is rarely needed on site for more than 12 months.

The production fluids that enter GC#1 are treated to remove gas and water. There are four stages of separation to remove gas: High Pressure (HP), Intermediate Pressure (IP), Low Pressure (LP) (Slugcatcher), and LP (Third Stage). These vessels operate at progressively lower pressures to minimize gas compression requirements while removing the hydrocarbon gases from the crude oil. Water is removed from the LP (Slugcatcher) and dehydrator. To improve the crude oil and water separation process, the liquid production fluids are heated downstream of the low pressure separator. After the crude oil and water separation process, the crude oil from the third stage separator is cooled to meet custody transfer requirements at the Trans Alaska Pipeline System (TAPS) Pump Station 1 (PS-1) owned and operated by Alyeska Pipeline Service Company.

The hydrocarbon gas, which is removed from the IP and LP separators, is compressed by gas compressors and combined with gas removed from the HP separator. The combined hydrocarbon gas is then processed in the Triethylene Glycol (TEG) Dehydration Unit to remove water vapor, thereby preventing the formation of hydrates upon further gas cooling and dehydration. Gases that are flashed or stripped in the TEG Dehydration Unit’s Regenerator are recovered and recycled back to the process (they are not vented to atmosphere). A small portion of dehydrated/stripped hydrocarbon gas is used for fuel and gas lift injection and the remaining dehydrated gas is shipped to Central Gas Facility (CGF) and cooled to condense and remove butane and heavier hydrocarbons that are blended back into the crude oil stream before shipment to PS-1. The hydrocarbon gas is further compressed in the CGF gas injection compressors for re-injection into the reservoir.

Produced water is collected and treated to remove any entrained crude oil. Currently, the treated water is pumped into disposal wells located at GC#1 or injected back into the production reservoir on the well pads.

There are a number of emergency systems employed at GC#1. Emergency generators provide electrical power should primary electrical service be lost. The emergency power is typically used to drive process safety and life support systems. Liquid fuel-driven emergency fire water pumps provide back-up fire water supply in the event electrical power is lost to the primary electrically driven fire water pump and the electric jockey pumps.

An emergency flare system is used to safely dispose of hydrocarbon gases vented from process equipment to either prevent over-pressure due to process upset (unavoidable emergencies or malfunctions), process equipment startups or shutdowns, or to de-pressure for non routine repair purposes.

## EMISSION UNIT INVENTORY AND DESCRIPTION

Under 18 AAC 50.326(a), the Department requires operating permit applications to include identification of all emissions-related information, as described under 40 C.F.R. 71.5(c)(3).

The emission units at the stationary source that have specific monitoring, recordkeeping, and reporting requirements are listed in Table A of Operating Permit No. AQ0182TVP02.

Table A of Operating Permit No. AQ0182TVP02 also contains specific information on each of the emission units that are regulated by this permit and provided in the application. The table is provided for informational and identification purposes only. Specifically, the emission unit rating/size provided in the table does not create an enforceable limit.

## EMISSIONS

A summary of the potential to emit (PTE)[1] and assessable PTE is shown in Table H below. The "Total" column excludes the contribution from hazardous air pollutants, as explained below, and from $CO_2$e**.** The emissions listed in the table are estimates to be used for informational purposes only. The emissions summary does not create an enforceable limit to the stationary source.

**Table H – Emissions Summary, in Tons Per Year (TPY)**

| Pollutant | NOx | CO | PM-10 | $SO_2$ | VOC | $CO_2$e[2] | HAPs | Total |
|---|---|---|---|---|---|---|---|---|
| PTE (excluding NRE's) | 4,869 | 1,362 | 107 | 156 | 46 | 977,309 | 21.3 | 6,540 |
| Assessable PTE | 4,869 | 1,362 | 107 | 156 | 46 | 0 | 0 | 6,540 |

The assessable PTE listed under Condition 47.1 is the sum of the emissions of each individual air pollutant other than CO2e for which the stationary source has the potential to emit quantities greater than 10 tons per year (TPY).

For criteria pollutants, emissions are as provided in the Title V permit renewal application supplement dated November 14, 2011. The applicant estimated PTE's for NOx, CO, PM-10, and VOC based on AP-42 emission factors current as of the date of the permit renewal application submittal, source test results, vendor supplied emission factors, and any allowed emission rates and/or operational limits applicable to emission units at the stationary source. The applicant estimated potential emissions of $SO_2$ based on mass balance and an assumed fuel gas $H_2S$ concentration of 125 ppmv and a liquid fuel sulfur content of 0.15 percent by weight (based on the value used in air quality modeling submitted to the Department as part of a Title I permit application, not yet effective). For Greenhouse Gas (GHG) Emissions $CO_2$e, BPXA submitted calculations on November 14, 2011. BPXA estimated PTE based on the 2010 actual GHG

[1] *Potential to Emit* or *PTE* means the maximum capacity of a stationary source to emit a pollutant under its physical or operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source, as defined in AS 46.14.990(23), effective 12/3/05.

[2] $CO_2$e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its global warming potential (GWP).

emissions reported to EPA using the emission factors found in 40 C.F.R. 98, Subpart C, Tables C-1 and C-2.

The HAP emissions shown in Table H are the total HAP PTE for all regulated emission units at all aggregated GC#1 locations that define the stationary source. However, per 40 C.F.R. 71.2, emission from oil or gas exploration or production wells with their associated equipment are not aggregated when determining the total potential to emit HAPs. Therefore, emissions from units located at any drill site are not aggregated when determining the HAPs major status of the stationary source.

As provided in the Title V permit renewal application and application supplements, HAP emissions from combustion units were calculated using field data from GRI-HAPCalc version 3.01, AP-42 emission factors, and Ventura County Air Pollution Control District emission factors; and HAP emissions from tanks were estimated using TANKS v4.09d. HAP estimates were not included in the total in the table above because most HAPs are VOCs and remaining HAPs are PM. The stationary source is not a major source of HAPs. The highest individual HAP is formaldehyde at 5.11 TPY (less than 10 TPY) and cumulative HAPs total is 21.3 TPY (less than 25 TPY) from the aggregated stationary source.

## BASIS FOR REQUIRING AN OPERATING PERMIT

In accordance with AS 46.14.130(b), an owner or operator of a Title V source[3] must obtain a Title V permit consistent with 40 C.F.R. Part 71, as adopted by reference in 18 AAC 50.040.

Except for sources exempted or deferred by AS 46.14.120(e) or (f), AS 46.14.130(b) lists three categories of sources that require an operating permit:

- A major source;
- A stationary source including an area source subject to federal new source performance standards under Section 111 of the Clean Air Act or national emission standards for hazardous air pollutants under Section 112 of the Clean Air Act; and
- Another stationary source designated by the federal administrator by regulation.

This stationary source requires an operating permit because it is classified under 18 AAC 50.326(a), 40 C.F.R. 71.3(a), and EPA's March 2011 *PSD and Title V Permitting Guidance for Greenhouse Gases* as:

- A major stationary source of air pollutants, as defined in Section 302 of the Act, that directly emits or has the potential to emit 100 TPY or more of any air pollutant; and
- An existing source, that emits or has a PTE equal to or greater than 100,000 TPY of $CO_2$e **and** 100 TPY GHGs on a mass basis.

[3] *Title V source* means a stationary source classified as needing a permit under AS 14.130(b) *[ref. 18 AAC 50.990(111)]*.

# AIR QUALITY PERMITS

## Previous Air Quality Permit to Operate

The most recent permit-to-operate issued for this stationary source is Permit to Operate No. 9673-AA003, as amended through January 16, 1997 (Amendment 1). This permit-to-operate incorporated terms and conditions of EPA Prevention of Significant Deterioration (PSD) Permit Nos. PSD-X80-09, PSD-X81-01, and PSD-X81-13, which contain specific BACT requirements for the stationary source.

All stationary source-specific requirements established in this permit, as revised/replaced in Operating/Construction Permit No. AQ0182TVP01 Revision 2, are included in this renewal Title V operating permit as described in Table K. As discussed below, the construction permit portion of Permit No. AQ0182TVP01 Revision 2 was issued to replace Permit-to-Operate No. 9673-AA003 Amendment 1.

## Title I Permits

On November 26, 1997, BPXA submitted a construction permit application requesting revisions to Permit to Operate No. 9673-AA003 Amendment 1. The application was submitted with the initial Title V operating permit application. The Permittee proposed that terms and conditions of the permit-to-operate be updated and several BACT limits be modified. However, only the PSD permitting authority, U.S. EPA, can modify its own BACT limits.

On August 29, 1997, U.S. EPA revised the permits to include identification of specific equipment and tag number, apportion field-wide ton per year limits to facility–specific equipment group limits, and update emission limits based solely on AP-42 factors to the values in the edition of AP-42 that were current in 1997. The revisions requested for the BACT limits are as contained in the EPA PSD permits PSD-X80-09 (PSD II) PSD-X81-01 (PSD III), and PSD-X81-13 (PSD IV) amended through August 29, 1997.

BPXA also requested that the permit be updated to include cases where EPA has agreed with BPXA that if equipment permitted by EPA has more stringent owner requested limits that ADEC now imposes, the less restrictive federal limits are then superseded.

Table I and Table J below identify and explain the emission unit inventory corrections and emission limits revisions made to Permit to Operate No. 9673-AA003 Amendment 1. These revisions were done under Operating/Construction Permit No. AQ0182TVP01 issued on October 20, 2003, revised on February 17, 2004 and August 26, 2005. These updates are now carried forward to this renewal Title V Operating Permit No. AQ0182TVP02, as shown in Table K below.

## Table I – Emission Unit Inventory Revisions

| EU ID | Equipment Tag No. | Rating in Permit to Operate No. 9673-AA003 | Operating/ Construction Permit No. AQ0182TVP01 Revised Rating | Operating Permit No. AQ0182TVP02 Revised Rating | Explanation |
|---|---|---|---|---|---|
| **Group I - Gas Turbines** | | | | | |
| 3<br>4 | GTRB-51-8002A<br>GTRB-51-8002B | 29,100 Hp ISO each | N/A | N/A | Equipment removed from service. |
| <br>7<br>8 | Sulzer S3 Units<br>GTRB-01-7704A<br>GTRB-01-7704B | 8,400 Hp each | 7,910 Hp each | 7,910 Hp each | New information; carried forward as revised in Permit No. AQ0182TVP01. |
| **Group II - Gas-Fired Heaters** | | | | | |
| 9<br>10<br>11 | GTRB-51-8001A<br>GTRB-51-8001B<br>GTRB-51-8001C | 2,500 Hp ISO | 2,500 Hp ISO | N/A | Equipment removed from service. |
| 14<br>15<br>16<br>17 | B-01-001<br>B-01-002<br>B-01-003<br>B-01-004 | 20.9 MMBtu/hr each [heat input, LHV]<br>(Dual Fuel-fired) | 20.9 MMBtu/hr each [heat input, LHV]<br>(Dual Fuel-fired) | 20.9 MMBtu/hr each [heat input, LHV]<br>(Gas-fired only) | Units are no longer used for liquid fuel combustion; only gas-fired. |
| 18<br>19 | B-01-0067<br>B-01-0068 | 5.5 MMBtu/hr each | 8.2 MMBtu/hr each | 8.2 MMBtu/hr each | The burners in these units were replaced in October 1990. The revised rating reflects the maximum heat input design value for these heaters. Carried forward as revised in Permit No. AQ0182TVP01. |
| **Group III - Liquid Fuel-Fired Equipment** | | | | | |
| 25 | GNED-51-8001A | 2,600 kW | 2,685 kW | 2,685 kW | New information. Corrected Tag No. from GNED-51-8004 to GNED-51-8001A in Permit No. AQ0182TVP02. |
| N/A | 86702 | 565 Hp | N/A | N/A | Unit removed from the stationary source. |
| 41<br>42 | PED-51-8001<br>KED-51-8001A | N/A | N/A | 160 Hp (approximate)<br>7 Hp | Units were previously deemed insignificant; now included in Permit No. AQ0182TVP02 because they are subject to NESHAP Subpart ZZZZ. |

| EU ID | Equipment Tag No. | Rating in Permit to Operate No. 9673-AA003 | Operating/ Construction Permit No. AQ0182TVP01 Revised Rating | Operating Permit No. AQ0182TVP02 Revised Rating | Explanation |
|---|---|---|---|---|---|
| **Group IV - Flares** | | | | | |
| 27<br>28<br>29<br>30<br>31<br>32<br>33<br>34<br>35<br>36<br>37 | FL-01-0001<br>FL-01-0002<br>FL-01-0003<br>FL-01-0004<br>FL-01-0005<br>FL-01-0006<br>FL-01-0007<br>FL-01-7001<br>FL-01-7002<br>FL-01-9902<br>FL-01-9907 | 1.95 MMscf/day (combined rating for EU IDs 27 - 37) | 1.95 MMscf/day (combined rating for EU IDs 27 - 37) | 1.95 MMscf/day (combined rating for EU IDs 29 – 32 and 34 - 37) | EU IDs 27, 28, and 33 not included in Permit No. AQ0182TP02; equipment removed from service. |
| **Group V – Fixed Roof Storage Tanks** | | | | | |
| 40 | T-51-8007 | 672,000 gallons | N/A | 672,000 gallons | Constructed in 1982. Existing tank converted from Methanol to ULSD (Diesel No. 1) storage tank, now subject to NSPS Subpart Ka. |

## Table J – Emission Limits Revisions[4]

| Pollutant | EU ID No. and Equipment Tag No. | Permit to Operate No. 9673-AA003 Limit | Permit No. AQ0182TVP02 Revised Limits[5] for Each Unit | Explanation |
|---|---|---|---|---|
| **NOx** | **EU IDs 1 & 2 Turbines (GE MS 5352B)**<br>GTRB-01-7000<br>GTRB-01-7001 | 173 ppmv @ 15% $O_2$ | 173 ppmvd @ 15% $O_2$ and 1,115 TPY each unit | EPA PSD II, III, and IV BACT and 8/29/97 permit revision. See Table D. |
| | **EU IDs 5 & 6 Turbines (Cooper Rolls RB211-24C)**<br>GTRB-51-3204<br>GTRB-51-3304 | 213 ppmv @ 15% $O_2$ | 213 ppmvd @ 15% $O_2$ and 999 TPY each unit | |
| | **EU IDs 7 & 8 Turbines (Sulzer/S3)**<br>GTRB-01-7704A<br>GTRB-01-7704B | 169 ppmv @ 15% $O_2$ | 169 ppmvd @ 15% $O_2$ and 230 TPY each unit | |

4 This table does not include all standard and general conditions.
5 These limits do not include applicable Alaska SIP limits, unless otherwise specified.

| Pollutant | EU ID No. and Equipment Tag No. | Permit to Operate No. 9673-AA003 Limit | Permit No. AQ0182TVP02 Revised Limits[5] for Each Unit | Explanation |
|---|---|---|---|---|
| | **EU IDs 12 & 13 Heaters (Econotherm)** H-51-8002A H-51-8002B | 0.08 lb/MMBtu | 0.08 lb/MMBtu and 71.4 TPY total for the two heaters combined | Permit No. 9673-AA003 for short-term limit of 0.08 lb/MMBtu. EPA PSD ton per year BACT limit superseded by more stringent ADEC operational limit and owner-requested firing rate limit and emission limit. See Table E. |
| | **EU IDs 14 – 19 Heaters (Cleaver Brooks and BS&B)** B-01-0001 B-01-0002 B-01-0003 B-01-0004 B-01-0067 B-01-0068 | 0.1 lb/MMBtu (except for unit B-01-0001 which has no limit) | No Limit | All units pre-date the PSD permit program. No BACT or other limits apply. |
| | **EU ID 20 Heaters (Smith)** B-01-9920 | 0.08 lb/MMBtu (at 4% excess $O_2$) | 0.08 lb/MMBtu (at 4% excess $O_2$) | No change – Owner requested limit to avoid PSD. See Table C. |
| | **All Emergency Equipment and Flares** | No Limit | No Limit | No BACT or other limits apply. |
| **CO** | **EU IDs 1 & 2 Turbines (GE MS 5352B)** GTRB-01-7000 GTRB-01-7001 | 109 lb/MMscf fuel gas | 0.17 lb/MMBtu and 269 TPY each unit | EPA PSD II, III, and IV BACT and 8/29/97 permit revision. See Table D. |
| | **EU IDs 5 & 6 Turbines (Cooper Rolls RB211-24C)** GTRB-51-3204 GTRB-51-3304 | | 0.17 lb/MMBtu and 193 TPY each unit | |
| | **EU IDs 7 & 8 Turbines (Sulzer/S3)** GTRB-01-7704A GTRB-01-7704B | | 0.17 lb/MMBtu and 56 TPY each unit | |

| Pollutant | EU ID No. and Equipment Tag No. | Permit to Operate No. 9673-AA003 Limit | Permit No. AQ0182TVP02 Revised Limits[5] for Each Unit | Explanation |
|---|---|---|---|---|
| | **EU IDs 12 & 13 Heaters (Econotherm)**<br>H-51-8002A<br>H-51-8002B | 0.018 lb/MMBtu (waste heat recovery mode firing) and 60 ppm (fresh air firing mode) | 60 ppmvd and 145.1 TPY for the two heaters combined (fresh air mode firing) | EPA PSD short-term limit superseded by more stringent owner-requested limit of 60 ppmvd during fresh air firing.<br>EPA PSD ton per year limits superseded by more stringent ADEC operational limit and owner-requested firing rate limit and emission limit.<br>Waste heat recovery operating mode no longer applies due to the removal of Cooper Rolls RB211 turbine Tag Nos. GTRB-51-8002A and GTRB-51-8002B from service.<br>See Table C. |
| | **EU IDs 14 – 19 Heaters (Cleaver Brooks and BS&B)**<br>B-01-0001<br>B-01-0002<br>B-01-0003<br>B-01-0004<br>B-01-0067<br>B-01-0068 | No Limit | No Limit | No BACT or other limit applies. |
| | **EU ID 20 Heaters (Smith)**<br>B-01-9920 | 0.018 lb/MMBtu | 0.018 lb/MMBtu | No change – Owner requested limit to avoid PSD. See Table C. |
| | **EU IDs 23 & 25 Diesel-fired Emergency Units**<br>GNED-01-0011<br>GNED-51-8001A | 0.00529 lb/Hp-hr | No Limit | No BACT or other limits apply. Value was an emission estimate only. |
| **Opacity** | **EU IDs 1, 2, & 5 – 8 All Gas-Fired Turbines**<br>GTRB-01-7000<br>GTRB-01-7001<br>GTRB-51-3204<br>GTRB-51-3304<br>GTRB-01-7704A<br>GTRB-01-7704B | 20%, 3 min/hr | 10%, consecutive 6-minute average | EPA PSD II, III, and IV as amended 8/29/97. See Table D. |

| Pollutant | EU ID No. and Equipment Tag No. | Permit to Operate No. 9673-AA003 Limit | Permit No. AQ0182TVP02 Revised Limits[5] for Each Unit | Explanation |
|---|---|---|---|---|
| | **EU IDs 12 & 13 Heaters (Econotherm Heaters)** H-51-8002A H-51-8002B | 5%, 3 minutes/hr | 5%, consecutive 6-minute average | EPA PSD III BACT and 8/29/97 permit revision. See Table E. |
| | **All Emergency Equipment and Flares** | No Limit | No Limit | No BACT or other limits apply. |
| **PM** | **EU IDs 1 & 2 Turbines (GE MS 5352B)** GTRB-01-7000 GTRB-01-7001 | 14 lb/MMscf | 0.014 lb/MMBtu and 22 TPY each unit | EPA PSD II and IV BACT and 8/29/97 permit revision. See Table D. |
| | **EU IDs 5 & 6 Turbines (Cooper Rolls RB211-24C)** GTRB-51-3204 GTRB-51-3304 | 14 lb/MMscf for GTRB-51-3204 only | 0.014 lb/MMBtu and 16 TPY for GTRB-51-3204<br>16 TPY for GTRB-51-3304 | |
| | **EU IDs 7 & 8 Turbines (Sulzer/S3)** GTRB-01-7704A GTRB-01-7704B | No Limit | 4.6 TPY each unit | |
| | **EU IDs 12 & 13 Heaters (Econotherm)** H-51-8002A H-51-8002B | No Limit | No Limit | No BACT limit applies. |
| | **EU IDs 14 – 19 Heaters (Cleaver Brooks and BS&B)** B-01-0001 B-01-0002 B-01-0003 B-01-0004 B-01-0067 B-01-0068 | No Limit | No Limit | No BACT limit applies. |
| | **EU ID 20 Heaters (Smith)** B-01-9920 | 2.5 lb/MMscf (permit does not indicate whether this value is an estimate or limit) | No Limit. | No BACT limit applies. Value was an emission estimate only. |
| | **All Emergency Equipment and Flares** | No Limit | No Limit | No BACT or other limits apply. |

| Pollutant | EU ID No. and Equipment Tag No. | Permit to Operate No. 9673-AA003 Limit | Permit No. AQ0182TVP02 Revised Limits[5] for Each Unit | Explanation |
|---|---|---|---|---|
| $SO_2$ | **EU IDs 1 & 2 Turbines (GE MS 5352B)** GTRB-01-7000 GTRB-01-7001 | No Limit | No Limit | No BACT or other limit applies to fuel |
| | **EU IDs 5 & 6 Turbines (Cooper Rolls RB211-24C)** GTRB-51-3204 GTRB-51-3304 | No Limit for GTRB-51-3204 (EU ID 5). 25 ppm $H_2S$ in fuel for GTRB-51-3304 3304 (EU ID 6). | No limit for GTRB-51-3204 (EU ID 5) and 5 TPY for GTRB-51-3304 (EU ID 6). 25 ppmv $H_2S$ content limit for EU ID 6 as an Owner Requested Limit to avoid PSD. Added a predetermined $H_2S$ limit of 125 ppmv after completion of air quality modeling. | $H_2S$ content limit for EU ID 6 is an Owner Requested Limit to avoid PSD.<br>Ton-per-year limit originates from EPA PSD IV BACT, as amended 8/29/97 for GTRB-51-3304 (EU ID 6).<br>Deleted the predetermined $H_2S$ limit of 125 ppmv from Permit No. AQ0182TVP01. Added "Upon completion of … the Permittee may apply for a permit modification to change this limit as approved".<br>See Condition 11 and Table D. |
| | **EU IDs 7 & 8 Turbines (Sulzer/S3)** GTRB-01-7704A GTRB-01-7704B | 25 ppm $H_2S$ in fuel | 25 ppmv $H_2S$ in fuel and 1.5 TPY each unit.<br>Deleted the predetermined $H_2S$ limit of 125 ppmv from Permit No. AQ0182TVP01. Added "Upon completion of … the Permittee may apply for a permit modification to change this limit as approved". | $H_2S$ content limit is an Owner Requested Limit to avoid PSD.<br>Ton-per-year limit originates from EPA PSD IV BACT as amended 8/29/97.<br>The Title I air quality modeling application has not yet been reviewed nor approved by the Department. The amended $H_2S$ limit will depend on the final decision on the pending Title I permit.<br>See Condition 11 and Table D. |
| | **EU IDs 12 & 13 Heaters (Econotherm)** H-51-8002A H-51-8002B | No Limit | No Limit | No BACT or other limit applies to fuel. |

| Pollutant | EU ID No. and Equipment Tag No. | Permit to Operate No. 9673-AA003 Limit | Permit No. AQ0182TVP02 Revised Limits[5] for Each Unit | Explanation |
|---|---|---|---|---|
| | **EU IDs 14 – 19 Heaters (Cleaver Brooks and BS&B)**<br>B-01-0001<br>B-01-0002<br>B-01-0003<br>B-01-0004<br>B-01-0067<br>B-01-0068 | No Limit | No Limit | No BACT or other limit applies to fuel. |
| | **EU ID 20 Heaters (Smith)**<br>B-01-9920 | No Limit | No Limit | No BACT or other limit applies to fuel. |
| | **All Emergency Equipment and Flares** | No Limit | No limit | No BACT or other limits apply. |
| **VOC** | **EU IDs 1, 2, & 5 – 8 All Gas-Fired Turbines**<br>GTRB-01-7000<br>GTRB-01-7001<br>GTRB-51-3204<br>GTRB-51-3304<br>GTRB-01-7704A<br>GTRB-01-7704B | No Limit | No Limit | No BACT or other limits apply. |
| | **EU IDs 12 – 20 All Heaters**<br>H-51-8002A<br>H-51-8002B<br>B-01-0001<br>B-01-0002<br>B-01-0003<br>B-01-0004<br>B-01,0067<br>B-01-0068<br>B-01-9920 | No Limit | No Limit | No BACT or other limits apply. |
| | **All Emergency Equipment and Flares** | No Limit | No Limit | No BACT or other limits apply. |

## Title V Operating Permit Application, Revisions, and Renewal History

The Permittee submitted an application for a Title V operating permit on November 26, 1997 (concurrently with the construction permit application). The Permittee submitted a supplement to the application December 11, 2002. On October 20, 2003, the Department issued Operating/Construction Permit No. AQ0182TVP01 that became effective November 20, 2003. This operating/construction permit incorporated all facility-specific terms and conditions of Permit-to-Operate No. 9673-AA003, as amended through January 16, 1997, as well as, the revisions requested for the BACT limits as contained in the EPA PSD permits PSD-X80-09 (PSD II), PSD-X81-01 (PSD III), and PSD-X81-13 (PSD IV) amended through August 29, 1997. In cases where equipment permitted by EPA has subsequently been limited by ADEC more stringently, the EPA PSD permit limit is then superseded. This permit revised and/or rescinded specific terms and conditions of Permit-to-Operate No. 9673-AA003.

Revision 1: On February 17, 2004, the Department issued Revision 1 to Operating/Construction Permit No. AQ0182TVP01 to clarify the use of the new terminology for "Stationary Source" and "Emission Unit" as applied to the aggregation issue for BPXA stationary sources and activities at the PBU. This discussion is found under the heading "Gathering Center #1 Stationary Source Identification" of the Statement of Basis. In this revision, the Department also modified Condition 9 of the initial Permit No. AQ0182TVP01. The Department removed the requirement to track non-emergency hours of operation of the emergency equipment, EU IDs 21 – 26 and clarified in the Statement of Basis that an exceedance of the operational hour limit is not a violation if the Department determines that the exceedance is due to an emergency.

Revision 2: BPXA submitted an administrative amendment on February 16, 2005 requesting that Well Pad K be added to the GC#1 stationary source. BPXA stated that the original Title V application mistakenly omitted the inclusion of that well pad. ADEC considered this an administrative amendment under 40 C.F.R. 71.7(d)(1)(ii). Currently, there are no significant emission units located on Well Pad K, so it was not necessary to modify any of the conditions of the permit. The only changes made in the permit and statement of basis was in the listing of Well Pad K within the group of well pads associated with Production Center GC #1, and therefore amended the defined stationary source. Revision 2 to Operating/Construction Permit No. AQ0182TVP01 was issued on August 26, 2005.

Renewal: The Permittee submitted an application for a renewal to the Title V operating permit on May 19, 2008 and was defaulted complete 60 days after receipt. The application was deemed technically complete on July 27, 2009. On November 14, 2011, the Department received by email an amendment to the renewal application that includes supplemental information on GC#1 Greenhouse Gas (GHG) Emissions, NESHAP Subpart ZZZZ requirements and applicability, and updated potential-to-emit calculations.

## COMPLIANCE HISTORY

The stationary source has operated at its current location since 1977. The Department permitted a fuel gas treatment system and supporting flare since November 29, 1974 (AQC 322) and flaring activities at GC#1 since August 22, 1975 (AQC 351). A review of the permit files, including the most recent full compliance evaluation conducted on March 22, 2010, indicated violations on several limits, and procedural and operational permitting requirements. Specifically, the evaluation discovered non-compliance with Conditions 3 (visible emissions limit and monitoring), 6 (sulfur monitoring), 13 ($H_2S$ limit), 25 (sulfur monitoring), 34 (monitoring of flare events) and 42 (asbestos notifications) of the Permit No. AQ0182TVP01, Revision 2. BPXA submitted a corrective action plan dated May 14, 2010 to address these issues.

## STATIONARY SOURCE-SPECIFIC REQUIREMENTS CARRIED FORWARD

Incorporated by reference at 18 AAC 50.326(j), 40 C.F.R. Part 71.2 defines "applicable requirement" to include the terms and conditions of any pre-construction permit issued under rules approved in Alaska's State Implementation plan and any pre-construction permits issued by U.S. EPA.

Alaska's State Implementation Plan includes the following types of pre-construction permits:

- Permit-to-operate issued before January 18, 1997 (these permits cover both construction and operations);
- Construction Permits issued effective January 17, 1997 or later; and
- Minor permits issued effective October 1, 2004 or later.

Pre-construction permit terms and conditions include both source-specific conditions and conditions derived from regulatory applicable requirements such as standard conditions, generally applicable conditions and conditions that quote or paraphrase requirements in regulation. These requirements include, but are not limited to, each source-specific requirement established in these permits issued under 18 AAC 50 that are still in effect at the time of this operating permit issuance. Table K lists the requirements carried over from Permit No. 9673-AA003 and Permit No. AQ0182TVP01 into Operating Permit No. AQ0182TVP02.

## Table K – Comparison of Previous Permit-to-Operate No. 9673-AA003 to Operating/Construction Permit Nos. AQ0182TVP01 Rev. 2 and AQ0182TVP02 Conditions[6]

| Permit No. 9673-AA003 Condition No. | Description of Requirement | Permit No. AQ0182TVP02 Condition No. | How Condition was Revised: Operating/Construction Permit No. AQ0182TVP01 Rev. 2 | How Condition was Revised: Operating Permit No. AQ0182TVP02 |
|---|---|---|---|---|
| 2 and Exhibit B | Comply with the most stringent of applicable emission standards and specifications set out in….and Exhibit B | 1, 6, 9, 11, 13 - 15, 17, 18 | The Alaska SIP limits were carried forward with amendments as listed in 18 AAC 50. Other limits have been carried forward without change or have been corrected, as stated in Table I and Table J. BACT limits are from EPA PSD permits PSD-X80-09 (PSD II), PSD-X81-01 (PSD III), and PSD-X81-13 (PSD IV) as revised 8/29/97. | Limits are carried forward as revised by Permit No. AQ182TVP01. Added conditions to gap-fill MR&R requirements for short-term emission limits. Waste heat recovery mode of operation no longer applies to EU IDs 12 and 13 due to the removal of Cooper Rolls RB211 turbine Tag Nos. GTRB-51-8002A and GTRB-51-8002B from service. In total, EU IDs 3, 4, 9, 10, 11, 27, 28, and 33 (as listed in Permit No. AQ0182TVP01 Rev. 2) have been removed from service and, therefore, are not included in this table. Therefore, any limits or associated MR&R for waste heat recovery operations or the removed emission units have been removed from the permit. |
| 5 | Operate EU IDs 21 through 26 not more than 200 hours per unit per year. | 13, Table B | Same requirements, different format. | Same requirements, different format. |
| 6 | Operating time limit for Source Tag No. 86072 | None; unit was removed from the stationary source | Not carried forward. | Not carried forward. |

[6] This table does not include all standard and general conditions.

| Permit No. 9673-AA003 Condition No. | Description of Requirement | Permit No. AQ0182TVP02 Condition No. | How Condition was Revised | |
|---|---|---|---|---|
| | | | Operating/Construction Permit No. AQ0182TVP01 Rev. 2 | Operating Permit No. AQ0182TVP02 |
| 7 | Operate EU IDs 12 and 13 in fresh-air firing mode not more than a combined total of 8,900 hours per year and only during shutdown of EU IDs 3 and 4. | 13, Table B | Removed clause regarding operation only during shutdown of Source ID(s) 3 and 4. These units have been removed from service so there is no longer a need to include the clause. | Carried forward as revised in Permit No. AQ0182TVP01. |
| 8 | Operate EU IDs 12 and 13 in waste heat recovery mode not more than a cumulative total of 5,600 hours per year. | None; EU IDs 3 and 4 were removed from service and thus there is no waste heat recovery mode of operation for EU IDs 12 and 13. | Not carried forward. | Not carried forward. |
| 9 | Operate EU IDs 3 and 4 not more than a combined total of 5600 hours per year. | None; EU IDs 3 and 4 were removed from service. | Not carried forward. | Not carried forward. |
| 10 | Operate EU IDs 9 – 11 not more than a combined total of 5600 hours per year. | None; EU IDs 9 – 11 were removed from service. | No change. | Not carried forward. |
| 15 and Exhibits B and C | Limit fuel gas $H_2S$ to 25 ppmv and conduct a monthly test of the fuel gas to determine the $H_2S$ as described in Exhibit C. | 9.2, 11, 30.1c | Incorporated the EPA-approved custom schedule and monitoring plan. Added a predetermined $H_2S$ limit of 125 ppmv after completion of air quality modeling. | No change on monitoring frequency and analytical methods. Added requirement to sample for fuel gas total sulfur as well as $H_2S$ and of each fuel gas supply. Deleted the predetermined $H_2S$ limit of 125 ppmv. Added footnote 9 and "Upon completion of … the Permittee may apply for a permit modification to change this limit as approved". |
| 16 and Exhibit C | Install, maintain, and operate instrumentation described in Exhibit C for EU IDs 12 and 13 to measure exhaust gas CO and $O_2$. | 12 | No change. | No change. |

| Permit No. 9673-AA003 Condition No. | Description of Requirement | Permit No. AQ0182TVP02 Condition No. | How Condition was Revised | |
|---|---|---|---|---|
| | | | Operating/Construction Permit No. AQ0182TVP01 Rev. 2 | Operating Permit No. AQ0182TVP02 |
| 17 and Exhibit C | Install, maintain and operate a continuous monitoring system for EU IDs 1, 2, and 5 - 11 to measure fuel consumption or estimate the total volume of fuel consumed by other means. Condition gives the option of obtaining the information without installing a CMS. | 16 | Similar requirements, different format. | Added monthly monitoring and recording of fuel consumption requirement for stationary source. |
| 21 and Exhibit D | Permittee shall submit quarterly facility operating reports…. | 71 | Same requirement. Report submittal is due 30 days after the end of each quarterly reporting period. | Same requirement with a change in the required submittal deadline from 30 days to 45 days after the end of each reporting period. |
| Exhibit A | EU ID 4 is limited to operation at 29,100 hp | None; EU ID 4 was removed from service. | None | None |
| Item 2, Exhibit D | Permittee shall report the number of hours of operation for each source, the quantity of fuel burned in each group, and the total quantity of fuel burned at the facility for each month. | 13.2, 15.2, 16.4 | No change, except hours of operation monitoring no longer required for flares. | Same requirements in Permit No. AQ0182TVP01, except monitoring of operating hours on fuel gas and liquid fuel for EU IDs 14 – 17 are no longer required. EU IDs 14 – 17 are no longer dual fuel- fired. |
| Exhibit C | Monitoring requirements for fuel gas and liquid fuel | 9 | Adopted the language used for standard condition for Sulfur Compound Emissions from Oil-Fired Fuel Burning Equipment (Standard Permit Condition XI, 18 AAC 50.346(c), 5/3/02). | Adopted the language used for standard condition for Sulfur Compound Emissions from Oil-Fired Fuel Burning Equipment for North Slope Diesel fuel and Other fuel oil (Standard Permit Condition XI, 18 AAC 50.346(c), 8/25/04). |

| Permit No. 9673-AA003 Condition No. | Description of Requirement | Permit No. AQ0182TVP02 Condition No. | How Condition was Revised: Operating/Construction Permit No. AQ0182TVP01 Rev. 2 | How Condition was Revised: Operating Permit No. AQ0182TVP02 |
|---|---|---|---|---|
| Exhibit D, Items 4 and 5 | Report the high, low, mean, and standard deviation of the fuel gas $H_2S$ and liquid fuel sulfur content annually | N/A | Condition has been deleted. The Department no longer requires this information. | N/A |
| N/A | Firing rate requirements for EU IDs 12 and 13 | 10 | Condition added as owner requested limit to avoid HAP major classification | No change. |

## NON-APPLICABLE REQUIREMENTS

Each permit is required to contain a discussion of all applicable requirements as set forth in 40 C.F.R. 71.6(a) adopted in 18 AAC 50.040(j). This section discusses standard conditions that have been removed from the permit or are not included for specific reasons.

- **Risk Management Plan (40 C.F.R. 68):** The stationary source is not subject to the general duty clause under the Clean Air Act Section 112(r)(1) (40 C.F.R. 68.10) because GC#1, a crude petroleum and natural gas production facility does not process or store regulated flammable or toxic substances in excess of threshold quantities in a process as determined in §68.115.
- **General Control Device and Work Practices Requirements 40 CFR 60.18:** The flares at GC#1 were installed as safety devices for the production facility, not as control devices, so the general permit shield that applies to the GC#1 flares for 40 C.F.R. 60.18 is appropriate.

  Subpart Ka does not mention any requirement to use a flare as a control device for tanks subject to the subpart. Therefore, even if the flares were used as control devices for this tank, 40 C.F.R. 60.18 still would not apply because the tank is subject to the control requirements of Subpart Ka and not 40 C.F.R. 60.18.
- **Compliance Assurance Monitoring (CAM, 40 C.F.R. 64):** The stationary source does not use a control device to achieve compliance with any emission limitation or standard and is therefore not subject to Compliance Assurance Monitoring as it does not satisfy the criteria of 40 C.F.R. 64.2(a)(2). The CAM rule defines “control device” to include only add-on controls and excludes “inherent process equipment.” The closed vent system for the controlled process and storage tanks is “inherent process equipment” which was installed and is operated primarily for material recovery and safety reasons, not for compliance with air quality regulations. See 40 CFR 64.1 definitions of “control device” and “inherent process equipment.”

- **40 CFR 63, Subpart HH**. The stripped hydrocarbons emitted from the TEG dehydrator regenerator are captured and returned to the process without release into the atmosphere.
- **Oil and Gas Production Facility Standards, 40 CFR 63, Subpart HH:** The Alaska Oil and Gas Conservation Commission (AOGCC) provides statistics for crude oil pools in Alaska (See http://doa.alaska.gov/ogc/annual/current/annindex_current.html). The Prudhoe Bay Gathering Centers 1, 2 and 3 and Flow Stations (1, 2 and 3) each receive crude oil produced from the Prudhoe Bay Unit - Prudhoe Oil Pool. AOGCC's Pool Statistics for the Prudhoe Bay Unit - Prudhoe Oil Pool lists an Initial Producing GOR (see "Original GOR SCF/STB") of 730 scf per stock tank barrel and an API Gravity of 28 degrees. The Initial Producing GOR for the Prudhoe Bay pools, based on early (1968) production data, is below 0.31 cubic meters per liter (1750 scf/bbl). Additionally, the API Gravity of the produced crude oil is less than 40 degrees. BPXA claims that the Prudhoe Bay Gathering Centers (1, 2 and 3) and Flow Stations ( 1, 2 and 3) each exclusively process, store, or transfer crude oil produced from the Prudhoe Pool, which meets the definition of black oil (as defined in 40 C.F.R. 63.761).

## STATEMENT OF BASIS FOR THE PERMIT CONDITIONS

The State and federal regulations for each condition are cited in Operating Permit No. AQ0182TVP02. The Statement of Basis provides the legal and factual basis for each term and condition as set forth in 40 C.F.R. 71.6(a)(1)(i).

### Conditions 1 - 5, Visible Emissions Standard and MR&R

**Legal Basis:** These conditions ensure compliance with the applicable requirements in 18 AAC 50.055(a). 18 AAC 50.055(a) applies to the operation of fuel-burning equipment and industrial processes.

- EU IDs 1, 2, 5 – 8, 12 – 20 – 26, 29 – 32, and 34 – 37 are fuel burning equipment.

U.S. EPA incorporated these standards as revised in 2002 into the State Implementation Plan (SIP) effective September 13, 2007.

**Factual Basis:** Condition 1 prohibits the Permittee from causing or allowing visible emissions in excess of the limit in 18 AAC 50.055(a)(1).

MR&R requirements are listed in Conditions 2 through 5 of the permit.

Conditions 2 through 5 have been adopted into regulation as Standard Permit Condition (SPC) IX. These conditions have been modified as follows:

- The Department added a requirement in Condition 2 for the Permittee to state the intention of using the visible emission monitoring schedule in effect from the previous permit, if electing to do so, in the first operating report required by Condition 71 submitted under the renewed permit.
- The Department added a footnote in Condition 2.1 which states "Emergency operations are exempt from the visible emissions observations deadlines associated with emission unit "operation" under this condition." The Department approved of this footnote as logistically, it would be challenging to schedule and coordinate a certified reader to conduct readings during emergency operations.
- The Permittee has opted not to use the Smoke/No Smoke plan, and requested that this option not be included in the permit, so the Department did not include this provision in the condition.
- The Department revised the Standard Permit Condition language for flares by adding *"or within 12 months after the permit effective date, whichever is later"* at the end of the first sentence in Condition 5. The Department has also revised Footnote 3 from *"…for greater than one hour as a result of scheduled release operations, i.e. maintenance or well testing activities"* to *"… at a rate that exceeds the source's de minimis pilot, purge, and assists gas rates for a minimum of 18 consecutive minutes."*

Beyond as noted above, the Department has determined that the standard conditions adequately meet the requirements of 40 C.F.R. 71.6(a)(3). No additional emission unit or stationary source operational or compliance factors indicate the unit-specific or stationary-source-specific conditions would better meet the requirements. Therefore, the Department concludes that the standard conditions as modified meet the requirements of 40 C.F.R. 71.6(a)(3).

The Permittee must establish by actual visual observations that can be supplemented by other means, such as a defined Stationary Source Operation and Maintenance Program that the stationary source is in continuous compliance with the State's emission standards for visible emissions and particulate matter.

These conditions detail a stepwise process for monitoring compliance with the State's visible emissions and particulate matter standards for liquid and gas fired emission units. Equipment types covered by these conditions are internal combustion engines, turbines, heaters, boilers, and flares. Initial monitoring frequency schedules are established along with subsequent reductions or increases in frequency depending on the results of the self-monitoring program.

Reasonable action thresholds are established in these conditions that require the Permittee to progressively address potential visible emission problems from emission units either through maintenance programs and/or more rigorous tests that will quantify whether a specific emission standard has been exceeded.

Condition 5 was developed to provide a standardized version of flare monitoring that is not dependent upon the type or design of upstream equipment. It has been claimed that gas-fired flares normally burn without emitting visible emissions, but actual field data demonstrating this assumption is not available. However, gas-fired flares have been shown to smoke when a control device, i.e. a knockout drum, flare scrubber, gas or steam assist, or vapor recovery system malfunctions. Thus, the Condition sets out a protocol to collect actual field data to determine compliance with the 20 percent visible emission standard for flares. The Department modified the text from the Standard Permit Condition to trigger the periodic monitoring with the next flare events 12 months after the preceding event or permit issue date whichever is later to allow for a transition between the expiring permit's pre-standard condition obligations with the renewal permit's standardized language.

**Gas Fired:**

<u>Monitoring</u> – For EU IDs 1, 2, 5 – 8, and 12 – 20, the monitoring of gas fired emission units for visible emissions is waived, i.e. no source testing will be required. The Department has found that natural gas fired equipment inherently has negligible PM emissions. However, the Department can request a source test for PM emissions from any smoking equipment.

<u>Reporting</u> - The Permittee must state in each operating report whether only gaseous fuels were used in the equipment during the period covered by the report.

**Liquid Fuel-Fired:**

<u>Monitoring</u> – For EU IDs 21 – 24 (if required under Condition 1.2), EU IDs 25 and 26, and EU ID 41 (if required under Condition 1.5), the visible emissions shall be observed by the Method-9 plan as detailed in Condition 2. The Permittee has opted not to use the Smoke/No Smoke plan, so this option has been removed from the permit. Corrective actions such as maintenance procedures and either more frequent or less frequent testing may be required depending on the results of the observations.

EU IDs 25 and 26 have already undergone First Method 9 and subsequent VE monitoring schedule observations under the initial Title V Permit No. AQ0182TVP01. Therefore, the Permittee may continue to monitor according to the visible emission monitoring schedule in effect from the previous permit.

EU IDs 21 – 24, 41 and 42 do not qualify as insignificant per 18 AAC 50.326(d)(1) because they are subject to operational limits established under a Title I permit and NESHAP Subpart ZZZZ requirements, but are emergency and standby generator units that have potential emissions less than the significant emissions thresholds in 18 AAC 50.326(e). Potential emissions of EU ID 42 based on unlimited hours of operation are less than the significant status threshold. As long as EU IDs 21 – 24 meet the operational hour-limit in Condition 13 and for as long as EU ID 41 operates no more than 800 hour per rolling 12-month period, the units' emissions are below the significant status threshold. Therefore, no monitoring is required in accordance with Department Policy and Procedure No. AWQ 04.02.103, Topic # 3, dated October 8, 2004. The Permittee must annually certify compliance under Condition 72 with the visible emission standard.

Recordkeeping - The Permittee is required to record the results of all visible emission observations and record any actions taken to reduce visible emissions.

Reporting - The Permittee is required to report: 1) emissions in excess of the State visible emissions standard and 2) deviations from permit conditions. The Permittee is required to include copies of the results of all visible emission observations with the operating report.

**Flares:**

Monitoring for flares (EU IDs 29 – 32 and 34 – 37) requires periodic Method 9 observations of scheduled flaring events lasting at least 18 minutes. However, observed events are not required to last more than one hour. Events lasting at least 18 minutes may also be observed to satisfy the periodic monitoring requirement for flares. The Permittee must report the results of these observations to the Department.

### Conditions 6 - 8, Particulate Matter (PM) Standard and MR&R

**Legal Basis:** These conditions ensure compliance with the applicable requirement in 18 AAC 50.055(b). This requirement applies to operation of all industrial processes and fuel burning equipment in Alaska.

- EU IDs 1, 2, 5 – 8, 12 – 26, 29 – 32, 34 – 37, 41, and 42 are fuel-burning equipment.

These PM standards also apply because they are contained in the federally approved SIP effective September 13, 2007.

**Factual Basis:** Condition 6 prohibits emissions in excess of the state PM (also called grain loading) standard applicable to fuel-burning equipment and industrial processes. The Permittee shall not cause or allow fuel-burning equipment to violate this standard. MR&R requirements are listed in Conditions 7 through 8 of the permit.

**Gas Fired:**

For gas fired emission units, MR&R conditions are Standard Condition VIII adopted into regulation pursuant to AS 46.14.010(e). The Department determined that these standard conditions adequately meet the requirements of 40 C.F.R. 71.6(a)(3). No emission unit or stationary source operational or compliance factors indicate that unit-specific or stationary-source specific conditions would better meet these requirements. Therefore, the Department concluded that the standard conditions meet the requirements of 40 C.F.R. 71.6(a)(3).

Although periodic PM monitoring of gas-fired units is waived, the Department has the discretion to request a source test for PM emissions from any fuel burning equipment under 18 AAC 50.220(a) and 345(l).

**Liquid Fuel-Fired:**

Monitoring – For EU IDs 21 – 24 (if required under Condition 6.2), EU IDs 25 and 26, and EU ID 41 (if required under Condition 6.5), the Permittee is required to conduct PM source testing if threshold values for opacity are exceeded.

EU IDs 21 – 24, 41 and 42 do not qualify as insignificant per 18 AAC 50.326(d)(1) because they are subject to operational limits established under a Title I permit and NESHAP Subpart ZZZZ requirements, but are emergency and standby generator units that have potential emissions below the significant emissions thresholds in 18 AAC 50.326(e). Potential emissions of EU ID 42 based on unlimited hours of operation are below the significant status threshold. As long as EU IDs 21 – 24 meet the operational hour-limit in Condition 13 and for as long as EU ID 41 operates no more than 800 hour per rolling 12-month period, the units emissions are below the significant status threshold. Therefore, no monitoring is required in accordance with Department Policy and Procedure No. AWQ 04.02.103, Topic # 3, dated October 8, 2004. The Permittee must annually certify compliance under Condition 72 with the particulate emission standard.

Recordkeeping - The Permittee is required to record the results of PM source tests.

Reporting - The Permittee is required to report: 1) incidents when emissions in excess of the opacity threshold values have been observed, and 2) results of PM source tests. The Permittee is required to include copies of the results of all visible emission observations with the operating report.

**Flares:**

Monitoring of gas fired flares for particulate matter is waived, i.e. no source testing will be required, because of the difficulty and questionable results these tests produce when applied to flares. The Department has recognized this fact by incorporating the waiver in the State Implementation Plan (SIP) adopted in November 1984. This plan was approved as part of the September 13, 2007 SIP approval but not incorporated by reference. No recordkeeping or reporting is required.

**Condition 9, Sulfur Compound Emissions and MR&R**

**Legal Basis:** This condition requires the Permittee to comply with the sulfur compound emission standard for all fuel-burning equipment in the State of Alaska.

- EU IDs 1, 2, 5 – 8, 12 – 26, 29 – 32, and 34 – 37 are fuel-burning equipment.

These sulfur compound standards also apply because they are contained in the federally approved SIP effective September 13, 2007.

**Factual Basis:** The condition requires the Permittee to comply with the sulfur compound emission standard applicable to fuel-burning equipment. The Permittee may not cause or allow the affected equipment to violate this standard.

Sulfur dioxide comes from the sulfur in the fuel (e.g. coal, natural gas, fuel oils). Fuel sulfur testing will verify compliance with the $SO_2$ emission standard.

**Gaseous Fuels:**

Fuel sulfur testing will verify compliance with $SO_2$ emission standard. Mercaptans are a concentrated thiol molecule (e.g. ethanethiol) composed of hydrogen and sulfur used to detect the presence of natural gas by its strong odor as in t-butyl-mercaptan. Basically, it is the mercaptan that allows the presence of gas to be detected by its odor, so it is naturally used for leak detection. In addition, it occurs naturally in gas formations. However, by that same token it can raise the sulfur content of the natural gas and should be accounted for in determining compliance with the State sulfur compound emissions standard. The Department has therefore revised the basic MR&R requirements to monitor the total sulfur quantity, in addition to the $H_2S$ concentration, in the natural gas fuel due to the presence of mercaptans in the gas supply which raise the sulfur concentration. The Department retained the $H_2S$ concentration as cross referenced to the owner requested limit in Condition 11.

Condition 9.2 requires the Permittee to conduct a monthly analysis for the fuel gas 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) or 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1).

The Department elected not to accept the applicant's proposal to reduce monitoring frequency based upon fuels meeting the NSPS Subpart GG pipeline quality natural gas definition because the NSPS fuel sulfur standard is less stringent than a fuel sulfur content equivalent to the State sulfur compound standard and less stringent than the owner requested fuel sulfur limit. $H_2S$ contents of fuel gas burned in EU IDs 6 – 8 are currently subject to ORL specified in Condition 11. The Department also used this $H_2S$ content ORL to assure compliance with the State standard of 500 ppm for sulfur compound emissions.

The Permittee is required to report as State excess emissions whenever the fuel combusted causes sulfur compound emissions to exceed the standards in this condition. The Permittee is required to include the sulfur content analysis with the operating report.

**Liquid Fuels:**

For oil fired fuel burning equipment, the MR&R conditions are based on Standard Permit Conditions XI and XII adopted into regulation pursuant to AS 46.14.010(e). The Department corrected Condition 9.8b(i) to replace the text *"…method listed in 18 AAC 50.035 or another method approved in writing by the Department*" with *"…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)".* The text *"…or another method approved in writing by the Department"* was discarded during the Revised Action Plan submitted to EPA on July 15, 2007, as a result of the EPA Audit of the September 2006 Title V Program Review. This text is not to be used in subsequent permits since it allows a Permittee to bypass the public process for changing monitoring requirements by submitting off-record requests to change monitoring methods.

Beyond as noted above, the Department has determined that the standard permit conditions adequately meet the requirements of 40 C.F.R. 71.6(a)(3). No additional emission unit or stationary source operational or compliance factors indicate the unit-specific or stationary-source-specific conditions would better meet the requirements. Therefore, the Department concludes that the standard permit conditions as modified meet the requirements of 40 C.F.R. 71.6(a)(3).

**Conditions 10 - 18, Pre-Construction Permit Requirements**

**Legal Basis:** The Permittee is required to comply with all effective stationary source-specific requirements that were carried forward from previous EPA PSD permits, SIP approved permits to operate issued before January 18, 1997, SIP approved construction permit(s), SIP approved minor permits, operating permits issued between January 18, 1997 and September 30, 2004, or owner requested limits established under 18 AAC 50.225. These requirements include Best Available Control Technology limits, limits to ensure compliance with the attainment or maintenance of ambient air quality standards or maximum allowable ambient concentrations, and owner requested limits. State pre-construction requirements apply because they were originally developed through case-by-case action under a federally approved SIP or approved Operating Permit program. EPA approved the latest SIP effective September 13, 2007.

**Factual Basis:** Conditions 10 through 18 contain source-specific terms and conditions carried forward from Air Quality Control Permit-to-Operate No. 9673-AA003, as amended through January 16, 1997; PSD Permit Nos. PSD-X80-09, PSD-X81-01, and PSD-X81-13 as amended through August 29, 1997; and Operating/Construction Permit No. AQ0182TVP01 Revision 2. Note that the Department does not have authority to modify or remove terms and conditions of EPA's federal PSD Decisions. However, the Department may elect to streamline the operating permit in the event that the Department has imposed a more stringent term or condition.

Condition 10 contains a firing rate limit for EU IDs 12 and 13 (Econotherm heaters) of 181.5 MMBtu/hr each, carried forward as an owner requested limit issued in Construction/Operating Permit No. AQ0182TVP01. EU IDs 12 and 13 are waste heat recovery units with heat exchangers at a design rating of 320 MMBtu/hr. During waste heat recovery operation, 17.5 MMBtu/hr is supplied by the turbine exhaust and 302.5 MMBtu/hr is supplied from the supplemental firing of the John Zink burners. During fresh air firing operational mode, only the John Zink burners are operating using automatic fuel flow valve when the associated turbine is not in operation.

The Permittee requested a fresh air firing rate limit of 181.5 MMBtu/hr for these heaters in correspondence to ADEC dated December 11, 2002. This revision was enacted in Permit No. AQ0182TVP01. By adhering to this firing rate limit, BPXA intends to limit the stationary source potential to emit, and maintain stationary source status as a "minor facility" with respect to HAPs emissions.

In addition, BPXA notified the Department in the BPXA renewal application that the waste heat recovery mode of operation no longer applies to EU IDs 12 and 13. BPXA removed the Cooper Rolls RB211 turbine tag nos. GTRB-51-8002A and GTRB-51-8002B from service. Therefore, any limits or associated MR&R for waste heat recovery operations have been removed from this renewal permit. Condition 11 contains requirements carried over from Permit No. 9673-AA003 to Operating/Construction Permit No. AQ0182TVP01 Revision 2 and to this renewal permit. This condition requires that fuel burned in EU IDs 6 – 8 contain no more than a hydrogen sulfide content ($H_2S$) of 25 ppmv at standard conditions, annual average. Upon completion of a Department approved air quality modeling, the Permittee may apply for a permit modification to change the fuel gas $H_2S$ limit based on the ambient $SO_2$ impact demonstration in the air quality modeling.

Conditions 12, 15, and 16 contains monitoring, recordkeeping, and reporting requirements for flue gas carbon monoxide and oxygen, operational hours, and fuel consumption tracking carried over from Permit No. 9673-AA003 to Operating/Construction Permit No. AQ0182TVP01 Revision 2 and to this renewal permit. These conditions provide a mechanism to determine compliance with limits throughout this permit. An exceedance of the operational hour limit in Table B for the emergency equipment, EU IDs 21 – 26, is not a violation if the Department determines that the exceedance is due to an emergency.

Condition 13 contains requirements carried over from Permit No. 9673-AA003. The condition requires the Permittee to limit the number of hours of operation per consecutive 12-month period for emergency equipment, EU ID 21 – 26. The condition also limits the number of hours of operation of EU IDs 12 and 13 (Econotherm heaters). The units have an operational limit of 8,900 hours of fresh-air mode operation per year, combined.[7] Although these units were initially permitted by EPA under Permit No. PSD-X81-01 (PSD III), the EPA NOx and CO ton-per-year BACT limits were superseded by the more stringent NOx and CO ton-per-year limits equivalent to this operational limit in Condition 13 combined with the firing-rate limit in Condition 10. Consequently, the EPA did not carry the original NOx and CO BACT limits forward to the amended PSD permit, dated August 29, 1997.

Condition 14 contains requirements for EU IDs 12, 13, and 20 carried over from Permit No. 9673-AA003 and revised by Permit No. AQ0182TVP01. On April 4, 1996, BPXA requested an increase in the hours of fresh air firing mode of the EU IDs 12 and 13 (Econotherm heaters) from 100 to 8900 hours per year. ADEC and the BPXA concurred to limit the operation of the Econotherm heaters fuel flow valves in automatic operation only during fresh air firing mode and also limit the exhaust concentration to 60 ppmvd CO. This new limit was more stringent than the original EPA BACT short-term CO limit of 0.018 lb/MMBtu. As such, the original EPA BACT short-term CO limit has been superseded and EPA did not carry the heater BACT limits forward to the August 29, 1997 amendment to the EPA PSD III permit.

In the construction permit hygiene application dated November 25, 1997, BPXA requested a cumulative NOx limit for EU IDs 12 and 13 of 71.7 TPY and cumulative CO limit of 204.3 TPY (fresh air mode). In the application amendment, dated December 11, 2002, BPXA revised the requested NOx and CO emission limits to correct computational errors found in conjunction with the 1997 request and to account for the owner-requested firing rate limit of 181.5 MMBtu/hr for each of these heaters (Condition 10). ADEC carried forward the updated NOx emission limit of 71.4 TPY and the CO emission limit of 145.1 TPY (fresh air mode) in Condition 14 as modified by Permit No. AQ0182TVP01. These limits, which reflect the cumulative hourly restrictions and firing rate restrictions for these units, replace the heater BACT limits originally established by EPA.

[7] The limits for waste heat recovery mode operation are not carried forward to this permit because these heaters can no longer operate in this mode due to removal of the associated Cooper RB211 turbines (Tag Nos. GTRB-51-8002A and GTRB-51-8002B).

The BACT limits presented in Conditions 17 and 18 reflect the limits stated in the EPA PSD II, III, and IV permits, including revised emission limits granted by EPA on August 29, 1997, which were carried forward/revised in Operating/Construction Permit No. AQ0182TVP01 Revision 2. For EU IDs 1, 2, and 5 – 8 (turbines), the ton per year BACT emission limits apply for NOx, CO, and PM, and for EU IDs 6 – 8, the ton per year BACT emission limit also applies for $SO_2$. In addition, EPA also established short-term BACT emission limits for NOx, CO, PM/opacity.

The Permittee is required to calculate and report emissions to determine compliance with the annual emission limits. For compliance with the short-term emission limits, the Department has added source testing requirements. In addition, despite being gas fired, which normally requires no VE observation for compliance with the State visible emissions standard, the Department has imposed an annual VE observation requirement to demonstrate compliance with the more stringent federal BACT visible emission limits imposed on these units. Once a baseline of information regarding compliance with the BACT limit is accumulated during the 5-year term of this permit, the Permittee may request relaxation of the VE requirement upon permit renewal.

**Condition 19, Insignificant Emission Units**

**Legal Basis:** The Permittee is required to meet state emission standards set out in 18 AAC 50.055 for all industrial processes and fuel-burning equipment regardless of size.

**Factual Basis:** The condition re-iterates the emission standards and requires compliance for insignificant emission units not otherwise listed in the permit. The Permittee may not cause or allow their equipment to violate these standards. The Permittee identified insignificant emission units in the permit application which need not appear in the permit. All the insignificant emission units listed in the permit application are portable in nature and not always located at the stationary source. Included among the insignificant emission units are nonroad engines, which do not have any applicable requirements under this permit. Insignificant emission units are not listed in the permit unless specific monitoring, recordkeeping and reporting are necessary to ensure compliance.

Condition 19.4a requires certification as part of the annual compliance certification statement that the units did not exceed State emission standards during the previous year and did not emit any prohibited air pollution.

**Conditions 20 - 26, NSPS Subpart A Requirements**

**Legal Basis:** The Permittee must comply with those New Source Performance Standard (NSPS) provisions incorporated by reference for specific industrial activities as listed in 18 AAC 50.040[8].

Most affected facilities (with the exception of some storage tanks) subject to an NSPS are subject to Subpart A. At this stationary source, EU IDs 1, 2, 5 – 8, 20, 26, 38, 39, and 40 are subject to NSPS requirements and therefore subject to Subpart A.

Condition 20 – Start-up, shutdown, or malfunction record maintenance requirements in 40 C.F.R. 60.7(b) are applicable to all NSPS affected facility subject to Subpart A.

[8] EPA has not delegated to the Department the authority to administer the NSPS program as of the issue date of this permit.

Conditions 21 and 22 – NSPS excess emission reporting requirements and summary report form in 40 C.F.R. 60.7(c) & (d) are applicable to affected units that use continuous monitoring device and for turbines subject to Subpart GG that use periodic sulfur monitoring requirement in Condition 30.1a. The Department has included in Attachment A of the Statement of Basis a copy of the federal EEMSP summary report form for use by the Permittee.

Recordkeeping requirements in 40 C.F.R. 60.7(f) are applicable to all NSPS sources. (Satisfied by Condition 66).

Condition 23 – The Permittee has already complied with the initial performance test requirements in 40 C.F.R. 60.8 for EU IDs 1, 2, and 5 – 8. However, the Permittee is still subject to these requirements in the event of a new NSPS affected facility, in the event of a modification or reconstruction of an existing facility into an affected facility, or at such other times as may be required by EPA.

Condition 24 – Good air pollution control practices in 40 C.F.R. 60.11 are applicable to all NSPS sources subject to Subpart A (EU IDs 1, 2, 5 – 8, 20, 26, 38, 39, and 40).

Condition 25 – This condition states that any credible evidence may be used to demonstrate compliance or establishing violations of relevant NSPS standards for 1, 2, 5 – 8, 20, 26, 38, 39, and 40.

Condition 26 – Concealment of emissions prohibitions in 40 C.F.R. 60.12 are applicable to EU IDs 1, 2, 5 – 8, 20, 26, 38, 39, and 40.

**Factual Basis:** General provisions of 40 C.F.R. 60, Subpart A apply to owners or operators who are subject to a relevant subpart under Part 60, except when otherwise specified in an applicable subpart or relevant standard. The intent of Subpart A is to eliminate the repetition of requirements applicable to all owners or operators affected by NSPS.

**Condition 27, NSPS Subpart Dc Requirements**

**Legal Basis:** The NSPS applies to steam generating units for which construction, modification, or reconstruction commenced after June 9, 1989 and have maximum design heat input capacities of 29 MW (100 MMBtu/hr) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr). EU ID 20 was constructed on September 1, 1993 and has a maximum design heat input capacity of 25.5 MMBtu/hr and is, therefore, subject to Subpart Dc.

EU ID 20 burns natural gas fuel. Therefore, the only requirements this subpart require are fuel consumption monitoring and recordkeeping.

A 2006 amendment to Subpart Dc provides an alternative for keeping monthly instead of daily records of fuel combustion by affected units under certain circumstances. EU ID 20 qualify for this alternative because, as stated in 40 C.F.R. 60.48c(g)(2), the unit combusts only natural gas.

**Factual Basis:** These conditions require the Permittee to comply with the Subpart Dc. The Permittee may not cause or allow EU ID 20 to violate these requirements.

### Condition 28, NSPS Subpart Ka Requirements

**Legal Basis:** The NSPS Subpart Ka applies to sources that were built or modified after May 18, 1978 and prior to July 23, 1984. EU IDs 38 – 40 were constructed during this time frame, have a storage capacity greater than 40,000 gallons, and store petroleum liquids.

This condition requires that EU ID 38 maintains and operates with a vapor recovery system meeting the specifications of 40 C.F.R. 60.112a(a)(3) and in accordance with the Operations and Maintenance Plan developed in compliance with 40 C.F.R. 60.113a(a)(2)(iii).

This condition also prohibits EU IDs 39 and 40 from storing a petroleum liquid with a true vapor pressure greater than 1.0 psia without first taking measures to comply with 40 C.F.R. 60.112a, §60.113a, and/or §60.115a, as applicable. Monitoring shall consist of an annual certification that the Permittee stored only Arctic Heating Fuel, Diesel Fuel, or Jet A in EU IDs 39 and 40, or if other materials are stored in EU IDs 39 and 40 that the true vapor pressure of the material stored is 1.0 psia or less.

**Factual Basis:** These conditions require the Permittee to comply with the Subpart Ka. The Permittee may not cause or allow EU IDs 38 – 40 to violate these requirements.

### Conditions 29 - 30, NSPS Subpart GG Requirements

**Legal Basis:** These conditions prohibit the Permittee from exceeding emission standards set out in Subpart GG. NSPS Subpart GG applies to stationary gas turbines with a heat input at peak load (maximum load at 60 percent relative humidity, 59 degrees F, and 14.7 psi) equal to or greater than 10.7 gigajoules per hour (10 MMBtu/hr), based on the lower heating value of the fuel fired and constructed, modified, or reconstructed after October 3, 1977.

**Factual Basis:** These conditions incorporate NSPS Subpart GG NOx emission and sulfur compound limits. The Permittee may not allow equipment to violate these standards.

*NOx Standard:* For a turbine subject to 40 C.F.R. 60.332, the NOx standard is determined by the following equation:

$$STD_{NOX} = 0.015(14.4/Y) + F$$

where,

| | | |
|---|---|---|
| $STD_{NOx}$ | = | allowable NOx emissions (percent by volume at 15 percent oxygen and on a dry basis) |
| $Y$ | = | manufacturer's maximum rated heat input (kJ/W-hr), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the affected emission unit. The value of Y shall not exceed 14.4 kJ/W-hr |
| $F$ | = | NOx emissions allowance for fuel bound nitrogen, percent by volume, assumed to be zero for Alaska fuel. |

Based on the manufacturer's heat rating at manufacturer's rated peak load, and assuming fuel bound nitrogen of zero, the NOx standard is 173 ppmv at 15 percent $O_2$ dry exhaust basis from EU IDs 1 and 2; 213 ppmv at 15 percent $O_2$ dry exhaust basis from EU IDs 5 and 6; and 169 ppmv at 15 percent $O_2$ dry exhaust basis from EU IDs 7 and 8.

*$SO_2$ Standard:* The Permittee is required to comply with one of the following sulfur requirements for EU IDs 1, 2, 5 – 8, and 26 (turbines):

(1) do not cause or allow $SO_2$ emission in excess of 0.015 percent by volume, at 15 percent $O_2$ and on a dry basis (150 ppmv), or

(2) do not cause or allow the sulfur content for the fuel burned in EU IDs 1 – 9 to exceed 0.8 percent by weight.

The Permittee chooses to comply with option (2) above.

*Exemptions:* Gas turbines exempted from NSPS Subpart GG emission standards are as provided in 40 C.F.R. 60.332(e) – (l). EU ID 26 meets the definition of an emergency gas turbine and is, therefore, exempt from the Subpart GG NOx emission limits under 40 C.F.R. 60.332(g). 40 C.F.R. 60.332(g) exemptions include emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and fire fighting gas turbines.

**Condition 29.1 - 29.3, NOx Monitoring, Recordkeeping, and Reporting**

**Legal Basis:** Periodic monitoring, recordkeeping, and reporting are included in Condition 29.1 through 29.3 for all turbines that normally operate for greater than 400 hours in a 12 month period. This additional monitoring is necessary to ensure that turbine emissions comply with the NSPS NOx standard and is required under 40 C.F.R. 71.6(a)(3) as the subpart does not contain MR&R sufficient for an operating permit.

**Factual Basis:** The Department does not have enough information to make categorical determinations that certain types of turbines, or turbines with emission test results below a certain percentage of the Subpart GG NOx emission limit will inherently comply with the Subpart GG limit at all times and will never need additional testing. After a sufficient body of NOx data is gathered under monitoring conditions for compliance with 40 C.F.R. 60, Subpart GG, the Department may find that it has enough information to make such categorical determinations. In that event, the Department would revise the NOx monitoring conditions. The Department may determine that to assure compliance it is necessary to retain or increase the current monitoring frequency.

These conditions do not include the initial NSPS performance test requirements as the Subpart A conditions cover these requirements. If an existing or new turbine under this permit is still subject to the performance test requirement of 40 C.F.R. 60.8 is covered under the Subpart A related conditions.

The intent of these conditions is that turbines or groups of turbines be routinely tested on no less than a 5-year cycle. If the most recent performance test on a turbine showed NOx emissions at less than or equal to 90 percent of each of the limits shown in Conditions 17 and/or 29 then periodic monitoring is required within a year of the effective date of the permit, or within a year of exceeding 400 hours of operation within a 12-month period any time it has been more than 4 years since the latest performance test was completed. For clarification, the Department added a 6 month cut-off date for triggering source testing within 1 year after the permit effective date in accordance with Condition 29.1a(i)(A). The 6-month trigger is used to assess if a turbine typically operates more than 400 hours in a 12-month period and should, therefore, be subject to the requirement of completing a testing within 1 year of the permit effective date if it has been greater than 4 years since the last test was completed.

If the most recent performance test showed operations at greater than 90 percent of the limits listed in Conditions17 and/or 29, then periodic monitoring source testing is required every year until two consecutive tests show emissions at less than or equal to 90 percent of the limit.

The condition does not state how load must be measured. For some turbines it may be possible to directly measure load as either mechanical or electrical output. For others, it may be necessary to calculate load indirectly based on measurements of other parameters. The Department is not attempting to dictate what method is most appropriate through the permit condition, but should evaluate the adequacy of methods of calculating load based on the load monitoring proposed by the Permittee.

Subpart GG defines "emergency gas turbine[9]" and exempts turbines meeting that definition from the GG emission standards. Some turbines may be operated as standby equipment but not meet the definition of emergency turbine, so the Department has added a Method 20, or Method 7E and either Method 3 or 3A monitoring threshold of 400 hours per 12-month period. For turbines expected to operate less than 400 hours the Department has also added recordkeeping for hours of operation. The Department does not intend to require the Permittee to operate a turbine solely for the purpose of testing.

The condition requires testing at a range of loads, consistent with the performance test requirements in Subpart GG, that is, test at 30, 50, 75, and 100 percent load. If testing at these four loads is not reasonable, the condition allows the Permittee to propose to the Department what test loads will be reasonable and adequate, and the Department will have the responsibility to make a finding on that proposal. If EPA has already approved alternative test loads for the initial performance test the Department would allow those test loads if the information that went into that decision were still representative of the turbine operation.

In Condition 29.1b(ii)(C)(4), the Department considers "fuel type" to mean, for liquid fuels a type of fuel as described in an ASTM or similar fuel specification.

Load measurements or load calculations from load surrogate measurements are for one-hour periods. The intent is to match the averaging period for the test method. Method 20 identifies a number of traverse points that vary with the size of the stack. From these points the tester is to choose at least 8 points for NOx measurements. The time at each point is to be at least one minute plus the average response time of the instrument. The recorded value is the average steady state response. Presumably, the steady state response would exclude some or all of the response time of the instrument. Three runs are to be done at each test load.

The three runs would represent 24 minutes of measurement time or more. A one-hour average load is therefore a reasonable approximation of a load period corresponding to the test method.

[9] *Emergency Gas Turbine* means any stationary gas turbine that operates as a mechanical or electrical power source only when the primary power source for a stationary source has been rendered inoperable by an emergency situation, as defined in 40 C.F.R. 60.331(e), effective 7/1/07.

## Conditions 30.1 - 30.4, $SO_2$ Monitoring, Recordkeeping, and Reporting

**Legal Basis:** These conditions require the Permittee to comply with NSPS Subpart GG $SO_2$ or fuel quality monitoring, record keeping and reporting.

**Factual Basis*:*** Monitoring, recordkeeping, and reporting requirements for these conditions are described in NSPS Subpart GG and have been referenced here. No additional monitoring outside of the Subpart GG requirements is necessary to ensure compliance with the NSPS $SO_2$ standard.

*Monitoring*: Condition 30.1 incorporates NSPS Subpart GG fuel sulfur monitoring requirements and the fuel gas monitoring requirements of the EPA approved alternative monitoring plan and schedule granted to BPXA in accordance with 40 C.F.R. 60.334(i)(3). EPA approved the alternative fuel gas monitoring plan and schedule in correspondence dated May 8, 1996, August 19, 1996, and October 2, 1997. Per Condition 30.1c, an affected facility for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

Per 40 C.F.R. 60.334(h)(3), 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. Therefore, no monitoring of total sulfur content is necessary for EU IDs 1, 2, 5 – 8, and 26 if they burn natural gas. The Permittee may submit a certified statement to the Department indicating that the fuel gas combusted at the stationary source meets the definition of natural gas in 40 C.F.R. 60.331(u), pursuant to 40 C.F.R. 60.334(h)(3).

*Recordkeeping*: The Permittee is required to maintain records of all sulfur monitoring data required by NSPS Subpart GG for five years as set out in 40 C.F.R. 71.6(a)(3)(ii)(B). This requirement is stated in Condition 66.

*Reporting*: NSPS Subpart GG fuel sulfur reporting requirements, as established under the approved custom fuel monitoring schedule for gas fired units, are incorporated in the permit in Condition 30.4. According to the custom fuel monitoring schedule approved in correspondence dated October 18, 1993 and incorporated in Condition 30.4a(ii), the Permittee is required to submit results of fuel gas $H_2S$ monitoring to EPA at least annually.

For the purpose of the EEMSP reports and summary report required under 40 C.F.R. 60.7(c) and (d) and stated in Conditions 21 and 22, the Permittee is required to report as excess emissions any period during which the sulfur content of the fuel being fired in the turbine exceeds 0.8 percent. As of 7/1/07 (the adoption date of 40 C.F.R. 60 by the State of Alaska as of the effective date of this permit), Subpart GG 40 C.F.R. 60.334(j)(5) requires EEMSP reporting 30 days after the end of each 6-month period, but the alternative monitoring schedule approved for Gathering Center #1 (GC#1) reduces the required frequency of these reports to at least annually, as set out in Condition 30.4a(ii). As stated in Conditions 21, 22, and 70, reports are to be submitted to the Department and EPA, and summarized in the operating report required under Condition 71. However, per Conditions 30.1b and 30.4a(iv), and pursuant to 40 C.F.R. 60.334(h)(3) and 60.334(i), the Permittee may elect not to monitor or report the total sulfur content of a gaseous fuel combusted by affected emission units if the fuel is demonstrated to meet the definition of natural gas under 40 C.F.R. 60.331(u), regardless of whether an existing custom schedule approved by the Administrator requires such monitoring and reporting.

Condition 30.4b requires copies of the results from the monitoring requirements in Condition 30.3 be included in the operating report required under Condition 71. State excess emissions and permit deviation reports are to be submitted in accordance with Condition 30.4c.

**Condition 31, NESHAPs Subpart A Requirements**

**Legal Basis:** Most sources subject to a NESHAPs requirement are subject to Subpart A. This stationary source is subject to NESHAPs Subpart ZZZZ and therefore is subject to the general provisions of Subpart A as specified in the provisions for applicability of Subpart A in the corresponding NESHAP subpart (Table 8 of Subpart ZZZZ).

**Factual Basis:** Subpart A contains the general requirements applicable to all affected facilities (sources) subject to NESHAPs. In general, the intent of NESHAPs is to regulate specific categories of stationary sources that emit or have the potential to emit one or more hazardous air pollutants. Since the only currently applicable category subpart is 40 C.F.R. 63 Subpart ZZZZ, Condition 31 requires compliance with the applicable provisions of NESHAP Subpart ZZZZ, Table 8, which addresses the portions of 40 C.F.R. 63 Subpart A that could apply to engines affected by Subpart ZZZZ.

**Conditions 32 – 36, NESHAPs Subpart ZZZZ Requirements**

**Legal Basis:** The Department has incorporated by reference the NESHAPs requirements effective July 30, 2010, for specific industrial activities, as listed in 18 AAC 50.040(c). NESHAP Subpart ZZZZ applies to any existing, new, or reconstructed stationary reciprocating internal combustion engines (RICE) located at a major or area source of HAP emissions, excluding stationary RICE units being tested at a stationary RICE test cell/stand. This stationary source is an area source of HAP emissions accessible by the Federal Aid Highway System (FAHS) subject to the provisions of NESHAP Subpart ZZZZ under 40 C.F.R. 63.6590(a)(1)(iii) for existing RICE (EU IDs 21 – 25, 41, and 42) whose construction commenced before June 12, 2006.

**Factual Basis:** EU IDs 21 – 25, 41, and 42 are designated as affected sources subject to Subpart ZZZZ because they are existing emergency (EU IDs 21 – 25), non-emergency black start (EU IDs 41) and non-emergency (EU ID 42) stationary CI RICE located at an area source of HAP emissions. These affected RICE units are subject to the management and work practice standards in Conditions 32 and 32. The existing unit compliance due date is no later than May 3, 2013.

For EU IDs 21 – 25, 41, and 42, Conditions 32 through 36 include all applicable standards and MR&R requirements according to engine use (emergency, non-emergency, black start) and ratings set out for existing stationary CI RICE located at an area source of HAP emissions. The Permittee is required to operate and maintain the existing stationary RICE according to the manufacturer's written instructions or procedures developed by the Permittee in a manner consistent with good air pollution control practice for minimizing emissions.

For emergency engines, EU IDs 21 – 25, the Permittee is required to install a non-resettable hour meter in each unit for accurate recording and monitoring to demonstrate compliance with the management, work practice standards and operational hour limitations set out for emergency RICE. For stationary emergency RICE, the unit is allowed 100 hours for maintenance check and readiness testing unless federal, state, or local standards require beyond 100 hours per year for the same purpose. The Permittee is not allowed to operate the emergency RICE for purposes other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as allowed under 40 C.F.R. 63.6640(f). The 50 hours allowed for non-emergency situations are counted towards the 100 hours per year provided for maintenance and testing. There is no time limit on the use of emergency stationary RICE in emergency situations. Should any of the emergency engines no longer meet the criteria for an emergency engine, as defined in 40 C.F.R. 63.6675, the emission unit will need to meet all applicable requirements for non-emergency engines

For non-emergency black start RICE (EU 41), the management practice standards are similar to those of emergency RICE (EU IDs 21 – 25) as set out in Condition 33.1.

For non-emergency, non-black start RICE with rating ≤ 300 Hp (EU ID 42), the management practice standards are also the same, except that oil and filter change is less frequent at every 1,000 hours of operation compared to a frequency of every 500 hours of operation required for each of EU IDs 21 – 25 and 41. General work practice standards, monitoring, recordkeeping, and reporting are as provided in Conditions 32 – 36.

Per 40 C.F.R. 63.6645(a)(5), the Permittee is not required to submit an initial notification for an existing stationary emergency RICE or existing stationary RICE that is not subject to any numerical emission standards.

**Condition 37, Asbestos NESHAP**

**Legal Basis:** The condition requires the Permittee to comply with asbestos demolition or renovation requirements in 40 C.F.R. 61, Subpart M. This condition ensures compliance with the applicable requirement in 18 AAC 50.040(b)(1) and (2)(F). The asbestos demolition and renovation requirements apply if the Permittee engages in asbestos demolition or renovation.

**Factual Basis:** Because these regulations include adequate monitoring and reporting requirements and because the Permittee is not currently engaged in such activity, simply citing the regulatory requirements is sufficient to ensure compliance with these federal regulations.

**Condition 38, Refrigerant Recycling and Disposal**

**Legal Basis:** This condition ensures compliance with the applicable requirement in 18 AAC 50.040(d) and applies if the Permittee engages in the recycling or disposal of certain refrigerants. The condition requires the Permittee to comply with the standards for recycling and emission reduction of refrigerants set forth in 40 C.F.R. 82, Subpart F, which will apply if the Permittee uses certain refrigerants and engages in the recycling or disposal of certain refrigerants.

**Factual Basis:** Because these regulations include adequate monitoring and reporting requirements and because the Permittee is not currently engaged in such activity, simply citing the regulatory requirements is sufficient to ensure compliance with this federal regulation.

**Condition 39, NESHAPs Applicability Determinations**

**Legal Basis:** The Permittee has the responsibility to determine if specific federal regulations apply to its stationary sources.

**Factual Basis:** The Permittee has conducted an analysis of the stationary source and determined that it is not a major HAPs stationary source based on emissions.

**Condition 40, NSPS and NESHAP Reports**

**Legal Basis:** The Permittee is required to provide the Department with a copy of each report submitted to EPA for units subject to NSPS or NESHAP federal regulations under 18 AAC 50.326(j)(4). 40 C.F.R. 70 Appendix A documents that EPA fully approved the Alaska operating permit program effective November 30, 2001.

**Factual Basis**: The condition supplements the specific reporting requirements in 40 C.F.R. 60, 40 C.F.R. 61, and 40 C.F.R. 63. The reports themselves provide monitoring for compliance with this condition.

**Conditions 41 - 42, Halon Prohibitions**

**Legal Basis:** These prohibitions apply to all stationary sources that use halon for extinguishing fires and as an inert gas to reduce explosion risk. The condition prohibits the Permittee from causing or allowing violations of these prohibitions. The stationary source uses halon and is therefore subject to the federal regulations contained in 40 C.F.R. 82.

**Factual Basis:** These conditions incorporate applicable 40 C.F.R. 82 requirements. The Permittee may not cause or allow violations of these prohibitions.

**Conditions 43 - 45, Standard Terms and Conditions**

**Legal Basis:** These are standard conditions required under 18 AAC 50.345(a) and (e)-(g) for all operating permits. This provision is incorporated in the federally approved Alaska State operating permit program effective November 30, 2001, as updated effective November 9, 2008.

**Factual Basis:** These are standard conditions that apply to all permits.

**Condition 46, Administration Fees**

**Legal Basis:** This condition ensures compliance with the applicable requirement in 18 AAC 50.400-405 as derived from AS 46.14.130. This condition requires the Permittee, owner, or operator to pay administration fees as set out in regulation. Paying administration fees is required as part of obtaining and holding a permit with the Department or as a fee for a Department action.

**Factual Basis:** The owner or operator of a stationary source who is required to apply for a permit under AS 46.14.130 shall pay to the Department all assessed permit administration fees. The regulations in 18 AAC 50.400-405 specify the amount, payment period, and the frequency of fees applicable to a permit action.

### Conditions 47 - 48, Emission Fees

**Legal Basis:** These conditions ensure compliance with the applicable requirement in 18 AAC 50.410-420. The regulations require all permits to include due dates for the payment of fees and any method the Permittee may use to re-compute assessable emissions.

**Factual Basis:** These emission fee conditions are Standard Condition I under 18 AAC 50.346(b) adopted pursuant to AS 46.14.010(e). The Department determined that these standard conditions adequately meet the requirements of AS 46.14.250. No emission unit or stationary source operational or compliance factors indicate that unit-specific or stationary-source specific conditions would better meet these requirements. Therefore, the Department concluded that the standard conditions meet the requirements of AS 46.14.250.

These standard conditions require the Permittee to pay fees in accordance with the Department's billing regulations. The billing regulations set the due dates for payment of fees based on the billing date.

The assessable emissions are potential or projected emissions of each air pollutant authorized by the permit (AS 46.14.250(h)(1)).

The conditions allow the Permittee to calculate **actual** annual assessable emissions based on previous actual annual emissions. According to AS 46.14.250(h)(1)(B), assessable emissions are based on each air pollutant. Therefore, fees based on actual emissions must also be paid on any pollutant emitted whether or not the permit contains any limitation of that pollutant.

This standard condition specifies that, unless otherwise approved by the Department, calculations of assessable emission based on actual emissions use the most recent previous calendar year's emissions. Since each current year's assessable emission are based on the previous year, the Department will not give refunds or make additional billings at the end of the current year if the estimated emissions and current year actual emissions do not match.

### Condition 49, Good Air Pollution Control Practice

**Legal Basis:** This condition ensures compliance with the applicable requirement in 18 AAC 50.346(b)(5) and applies to all emission units, **except** those subject to federal emission standards, those subject to continuous emission or parametric monitoring, and for insignificant emission units; i.e., except EU IDs 1, 2, 5 – 8, 20, 26, 38 – 40, and EU IDs 21 – 25 starting May 3, 2013 (compliance due date for 40 C.F.R. Subpart ZZZZ).

**Factual Basis:** The Department adopted this condition under 18 AAC 50.346(b) as Standard Permit Condition VI pursuant to AS 46.14.010(e). This condition has been modified in the permit as follows. The Department added the text "EU IDs 21 – 25, 41, and 42 are subject to this condition only until the applicable compliance date as set forth in Condition 32" because on the compliance date (May 3, 2013), EU IDs 21 – 25, 41, and 42, units that are subject to NESHAPs Subpart ZZZZ standards, will no longer be subject to this State GAPCP condition and will instead be required to comply with Condition 32.1 (Federal GAPCP). Records kept in accordance with Condition 49.2 for units previously subject to Condition 49 need to be maintained for 5 years in accordance with Condition 66 even if a unit is no longer subject to this State GAPCP condition.

Beyond as noted above, the Department determined that this standard condition adequately meets the requirements of 40 C.F.R. 71.6(a)(3). No additional emission unit or stationary source operational or compliance factors indicate that unit-specific or stationary-source specific conditions would better meet these requirements. Therefore, the Department concluded that the standard condition as modified meets the requirements of 40 C.F.R. 71.6(a)(3).

Maintaining and operating equipment in good working order is fundamental to preventing unnecessary or excess emissions. Standard conditions for monitoring compliance with emission standards are based on the assumption that good maintenance is performed. Without appropriate maintenance, equipment can deteriorate more quickly than with appropriate maintenance. If appropriate maintenance is not applied to the equipment, the Department may have to apply more frequent periodic monitoring requirements (unless the monitoring is already continuous) to ensure that the monitoring results are representative of actual emissions.

The Permittee is required to keep maintenance records to show that proper maintenance procedures were followed, and to make the records available to the Department. The Department may use these records as a trigger for requesting source testing if the records show that maintenance has been deferred.

**Condition 50, Dilution**

**Legal Basis:** This condition prohibits the Permittee from using dilution as an emission control strategy as set out in 18 AAC 50.045(a). This State regulation applies to the Permittee because the Permittee is subject to emission standards in 18 AAC 50.

**Factual Basis:** The condition prohibits the Permittee from diluting emissions as a means of compliance with any standard in 18 AAC 50.

**Condition 51, Reasonable Precautions to Prevent Fugitive Dust**

**Legal Basis:** This condition requires the Permittee to use reasonable precautions when handling, storing or transporting bulk materials or engineering in an industrial activity in accordance with the applicable requirement in 18 AAC 50.045(d). Bulk material handling requirements apply to the Permittee because the Permittee may engage in bulk material handling, transporting, or storing; or will engage in industrial activity at the stationary source.

**Factual Basis:** The condition requires the Permittee to comply with 18 AAC 50.045(d), and take reasonable action to prevent particulate matter (PM) from being emitted into the ambient air. Since the stationary source is not a significant source of fugitive PM emissions, there is no need for monitoring or recordkeeping.

**Condition 52, Stack Injection**

**Legal Basis:** This condition ensures compliance with the applicable requirement in 18 AAC 50.055(g). It prohibits the Permittee from releasing materials other than process emissions, products of combustion, or materials introduced to control pollutant emissions from a stack (i.e. disposing of material by injecting it into a stack). Stack injection requirements apply to the stationary source because the stationary source contains a stack or source constructed or modified after November 1, 1982.

**Factual Basis:** No specific monitoring for this condition is practical. Compliance is ensured by inspections, because the emission unit or stack would need to be modified to accommodate stack injection.

**Condition 53, Air Pollution Prohibited**

**Legal Basis:** This condition ensures compliance with the applicable requirement in 18 AAC 50.110. The condition prohibits the Permittee from causing 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. Air Pollution Prohibited requirements apply to the stationary source because the stationary source will have emissions.

**Factual Basis:** While the other permit conditions and emissions limitations should ensure compliance with this condition, unforeseen emission impacts can cause violations of this standard. These violations would go undetected except for complaints from affected persons. Therefore, to monitor compliance, the Permittee must monitor and respond to complaints.

ADEC adopted this standard condition into 18 AAC 50.346(a) pursuant to AS 46.14.010(e). The Department determined that this condition adequately meets the requirements of 40 C.F.R. 71.6(a)(3). No emission unit or stationary source operational or compliance factors indicate that unit-specific or stationary-source specific conditions would better meet these requirements. Therefore, the Department concluded that the standard condition meets the requirements of 40 C.F.R. 71.6(a)(3).

The Permittee is required to report any complaints and injurious emissions. The Permittee must keep records of the date, time, and nature of all complaints received and summary of the investigation and corrective actions undertaken for these complaints and to submit copies of these records upon request of the Department.

**Condition 54, Technology-Based Emission Standard**

**Legal Basis:** The Permittee is required to take reasonable steps to minimize emissions if certain activity causes an exceedance of any technology-based emission standard in this permit. This condition ensures compliance with the applicable requirement in 18 AAC 50.235. Technology Based Emission Standard requirements apply to the stationary source because the stationary source contains equipment subject to a technology-based emission standard, such as BACT, MACT, LAER, NSPS or other “technologically feasible” determinations.

**Factual Basis:** The conditions of this permit list applicable technology-based emission standards and require excess emission reporting for each standard in accordance with Condition 70. Excess emission reporting under Condition 70 requires information on the steps taken to minimize emissions. Monitoring of compliance for this condition consists of the report required under Condition 70.

**Condition 55, Open Burning**

**Legal Basis:** The condition requires the Permittee to comply with the regulatory requirements when conducting open burning at the stationary source. This condition ensures compliance with the applicable requirement in 18 AAC 50.065. The open burning state regulation in 18 AAC 50.065 applies to the Permittee if the Permittee conducts open burning at the stationary source.

**Factual Basis:** No specific monitoring is required for this condition. The Department has incorporated the requirements of 18 AAC 50.065 by reference. Condition 55.1 requires the Permittee to keep "sufficient records" to demonstrate compliance with the standards for conducting open burning, but does not specify what these records should contain.

More extensive monitoring and recordkeeping is not warranted because the Permittee does not conduct open burning as a routine part of their business. Also, most of the requirements are prohibitions, which are not easily monitored. Compliance is demonstrated through annual certification required under Condition 72.

**Condition 56, Requested Source Tests**

**Legal Basis:** The Permittee is required to conduct source tests as requested by the Department. The Department adopted this condition under 18 AAC 50.345(k) as part of the federally approved State operating permit program effective November 30, 2001, as updated effective November 9, 2008.

**Factual Basis:** This condition ensures compliance with the applicable requirement in 18 AAC 50.220(a) and applies because this is a standard condition to be included in all operating permits. Monitoring consists of conducting the requested source test.

**Conditions 57 - 59, Operating Conditions, Reference Test Methods, Excess Air Requirements**

**Legal Basis:** These conditions ensure compliance with the applicable requirement in 18 AAC 50.220(b) and apply because the Permittee is required by the permit to conduct source tests. The Permittee is required to conduct source tests in the manner set out in Conditions 57 through 59.

**Factual Basis:** These conditions supplement the specific monitoring requirements stated elsewhere in this permit. Compliance monitoring with Conditions 57 through 59 consists of the test reports required by Condition 64.

**Condition 60, Test Exemption**

**Legal Basis:** This condition ensures compliance with the applicable requirement in 18 AAC 50.345(a) and applies when the emission unit exhaust is observed for visible emissions.

**Factual Basis:** As provided in 18 AAC 50.345(a), amended May 3, 2002, the requirements for test plans, notifications and reports do not apply to visible emissions observations by smoke readers, except in connection with required particulate matter testing.

**Conditions 61 - 64, Test Deadline Extension, Test Plans, Notifications and Reports**

**Legal Basis:** These conditions ensure compliance with the applicable requirement in 18 AAC 50.345(l) - (o) and apply because the Permittee is required to conduct source test by this permit.

**Factual Basis:** Standard conditions 18 AAC 50.345(l) - (o) are incorporated through these conditions. These standard conditions supplement specific monitoring requirements stated elsewhere in this permit. The source test itself monitors compliance with these conditions.

**Condition 65, Particulate Matter Calculations**

**Legal Basis:** This condition requires the Permittee to reduce particulate matter data in accordance with 18 AAC 50.220(f). It applies when the Permittee tests for compliance with the particulate matter standard in 18 AAC 50.055.

**Factual Basis:** The condition incorporates a regulatory requirement for particulate matter source tests. This condition supplements specific monitoring requirements stated elsewhere in this permit.

**Condition 66, Recordkeeping Requirements**

**Legal Basis:** Applies because the Permittee is required by the permit to keep records.

**Factual Basis:** The condition restates the regulatory requirements for recordkeeping, and supplements the recordkeeping defined for specific conditions in the permit. The records being kept provide an evidence of compliance with this requirement.

**Condition 67, Certification**

**Legal Basis:** This condition requires the Permittee to comply with the certification requirement in 18 AAC 50.205 and applies to all Permittees under EPA's approved State operating permit program effective November 30, 2001, as updated effective November 9, 2008.

**Factual Basis:** This standard condition is required in all operating permits under 18 AAC 50.345(j). This condition requires the Permittee to certify any permit application, report, affirmation, or compliance certification submitted to the Department. To ease the certification burden on the Permittee, the condition allows the excess emission reports to be **certified** with the operating report, even though it must still be **submitted** more frequently than the operating report. This condition supplements the reporting requirements of this permit.

**Condition 68, Submittals**

**Legal Basis:** This condition requires the Permittee to comply with standardized reporting requirement in 18 AAC 50.326(j) and applies because the Permittee is required to send reports to the Department.

**Factual Basis:** This condition requires the Permittee to send submittals to the address specified in this condition. The Permittee is required to submit an original and one copy of reports, compliance certifications, and other submittals required by this permit. Receipt of the submittal at the correct Department office is sufficient monitoring for this condition. This condition supplements the reporting requirements of this permit.

**Condition 69, Information Requests**

**Legal Basis:** This condition requires the Permittee to submit requested information to the Department. This is a standard condition from 18 AAC 50.345(i) of the federally approved State operating permit program effective November 30, 2001, as updated effective November 9, 2008.

**Factual Basis:** This condition incorporates a standard condition in regulation, which requires the Permittee to submit information requested by the Department. Monitoring consists of receipt of the requested information.

**Condition 70, Excess Emission and Permit Deviation Reports**

**Legal Basis:** This condition requires the Permittee to comply with the applicable requirement in 18 AAC 50.235(a)(2) and 18 AAC 50.240. Also, the Permittee is required to notify the Department when emissions or operations deviate from the requirements of the permit.

**Factual Basis:** This condition satisfies two State regulations related to excess emissions - the technology-based emission standard regulation and the excess emission regulation. Although there are some differences between the regulations, the condition satisfies the requirements of each regulation.

The Department adopted this condition as Standard Operating Permit Condition III under 18 AAC 50.346(c) pursuant to AS 46.14.010(e). The Department has determined that the standard condition adequately meets the requirements of 40 C.F.R. 71.6(a)(3). No additional emission unit or stationary source operational or compliance factors indicate the unit-specific or stationary-source-specific conditions would better meet the requirements. Therefore, the Department concludes that the standard condition meets the requirements of 40 C.F.R. 71.6(a)(3).

*Section 14, Notification Form*

The notification form contained in Standard Permit Condition IV meets the requirements of Chapter 50, Air Quality Control.

**Condition 71, Operating Reports**

**Legal Basis:** This condition ensures compliance with the applicable requirement in 18 AAC 50.346(b)(6) and applies to all permits.

**Factual Basis:** The condition restates the requirements for reports listed in regulation. The condition supplements the specific reporting requirements elsewhere in the permit. The reports themselves provide monitoring for compliance with this condition.

The Department used Standard Permit Condition VII as revised on September 27, 2010. For reporting, MR&R conditions are Standard Permit Condition VII adopted into regulation pursuant to AS 46.14.010(e). The Department has made a modification to Standard Permit Condition VII as incorporated into this permit by allowing quarterly reporting as requested by the Permittee instead of the standard semi-annual operating reports and a change on the due date for submittal from 30 days to 45 days following the last day of the reporting period. These changes satisfy the requirement for a "stationary source specific" change to the Standard Permit Condition. The Department has determined that the condition included in this permit meets the requirements of 40 C.F.R. 71.6(a)(3).

For renewal permits, the condition specifies that for the transition periods between an expiring permit and a renewal permit the Permittee shall ensure that there is date-to-date continuity between the expired permit and the renewal permit such that the Permittee reports against the permit terms and conditions of the permit that was in effect during those partial date periods of the transition. No format is specified. The Permittee may provide one report accounting for each permit term or condition for each of the effective permits during the certification period. Alternatively, the Permittee may choose to provide two reports – one accounting for reporting elements of permit terms and conditions from the end date of the previous operating report until the date of expiration of the old permit, and a second operating report accounting for reporting elements of terms and conditions in effect from the effective date of the renewal permit until the end of the reporting period.

**Condition 72, Annual Compliance Certification**

**Legal Basis:** This condition ensures compliance with the applicable requirement in 18 AAC 50.040(j)(4) and applies to all Permittees.

**Factual Basis:** This condition specifies the periodic compliance certification requirements, and specifies a due date for the annual compliance certification. The reports themselves provide monitoring for compliance with this condition.

Condition 72.2 provides clarification of transition periods between an expiring permit and a renewal permit to ensure that the Permittee certifies compliance with the permit terms and conditions of the permit that were in effect during those partial date periods involved in the transition. No format is specified. The Permittee may provide one report certifying compliance with each permit term or condition for each of the effective permits during the certification period, or may choose to provide two reports – one certifying compliance with permit terms and conditions from January 1 until the date of expiration of the old permit, and a second report certifying compliance with terms and conditions in effect from the effective date of the renewal permit until December 31.

This condition was further modified to allow the Permittee to submit one of the required two copies in electronic format. This change more adequately meets the requirements of 18 AAC 50 and agency needs, as the Department can more efficiently distribute the electronic copy to staff in other locations.

**Condition 73, Emission Inventory Reporting**

**Legal Basis:** This condition requires the Permittee to submit emissions data to the State to satisfy the Federal requirement that applies to the State to submit emission inventory data from point sources as required under 40 C.F.R. 51.321 (6/10/02). The requirement applies to sources defined as point sources in 40 C.F.R. 51.50. The State must report all data elements in Table 2A of Appendix A to Subpart A of 40 C.F.R. 51 to EPA (73 FR 76556).

**Factual Basis:** The Department has incorporated Standard Permit Conditions XV and XVI as adopted by regulation on September 27, 2010. The Department adopted these conditions under 18 AAC 50.346(b) pursuant to AS 46.14.010(e). The emission inventory data is due to EPA 12 months after the end of the reporting year (40 C.F.R. 51.30(a)(1) and (b)(1), 12/17/08). A due date of March 31 corresponds with sources reporting actual emissions for assessable emissions purposes and provides the Department sufficient time to enter the data into EPA’s electronic reporting system.

The air emissions reporting requirements under 40 C.F.R. Part 51 Subpart A apply to States; however, States rely on information provided by point sources to meet the reporting requirements of Part 51 Subpart A.

To ensure that the Department’s electronic system reports complete information to the National Emissions Inventory, Title V stationary sources classified as Type A in Table 1 of Appendix A to Subpart A of 40 C.F.R. 51 are required to submit with each annual report all the data elements required for the Type B source triennial reports (see also Table 2A of Appendix A to Subpart A of 40 C.F.R. Part 51). All Type A sources are also classified as Type B sources. However the department has streamlined the reporting requirements so Type A sources only need to submit a single type of report every year instead of both an annual report and a separate triennial report every third year.

**Condition 74, Permit Applications and Submittals**

**Legal Basis:** The Permittee may need to submit permit applications and related correspondence.

**Factual Basis:** Standard Condition XIV directs the applicant to send copies of all application materials required to be submitted to the Department directly to the EPA, in electronic format if practicable. This condition shifts the burden of compliance from the Department to ensure that copies of application materials are submitted to EPA by transferring that responsibility to the Permittee as allowed under 40 C.F.R. 71.10(d)(1).

**Conditions 75 - 77, Permit Changes and Revisions Requirements**

**Legal Basis:** The Permittee is obligated to notify the Department and EPA of certain off-permit source changes and operational changes under 18 AAC 50.326(j)(4). 40 C.F.R. 71.6(a)(8), (12), and (13) incorporated by reference under 18 AAC 50.040(j) require these provisions within this permit. 40 C.F.R. 70 Appendix A documents that EPA fully approved the Alaska operating permit program effective November 30, 2001.

**Factual Basis:** These are conditions required in 40 C.F.R. 71.6 for all operating permits to allow changes within a permitted stationary source without requiring a permit revision. The Permittee did not request trading of emission increases and decreases as described in 40 C.F.R. 71.6(a)(13)(iii); therefore, language addressing these provisions has not been included in this permit as part of Condition 75.

**Condition 78, Permit Renewal**

**Legal Basis:** The Permittee must submit a timely and complete operating permit renewal application if the Permittee intends to continue source operations in accord with the operating permit program under18 AAC 50.326(j)(3). The obligations for a timely and complete operating permit application are set out in 40 C.F.R. 71.5 incorporated by reference in 18 AAC 50.040(j)(3). 40 C.F.R. 70 Appendix A documents that EPA fully approved the Alaska operating permit program effective November 30, 2001.

**Factual Basis:** In accordance with AS 46.14.230(a), this operating permit is issued for a fixed term of five years after the date of issuance, unless a shorter term is requested by the permit applicant. The Permittee is required to submit an application for permit renewal by the specific dates applicable to the stationary source as listed in this condition. As stated in 40 C.F.R. 71.5(a)(1)(iii), submission for a permit renewal application is considered timely if it is submitted at least six months but no more than eighteen months prior to expiration of the operating permit. According to 40 C.F.R. 71.5(a)(2), a complete renewal application is one that provides all information required pursuant to 40 C.F.R. 71.5(c) and must remit payment of fees owed under the fee schedule established pursuant to 18 AAC 50.400. 40 C.F.R. 71.7(b) states that if a source submits a timely and complete application for permit issuance (including renewal), the source's failure to have a permit is not a violation until the permitting authority takes final action on the permit application.

Therefore, for as long as an application has been submitted within the timeframe allowed under 40 C.F.R. 71.5(a)(1)(iii), and is complete before the expiration date of the existing permit, then the expiration of the existing permit is extended and the Permittee has the right to operate under that permit until the effective date of the new permit. However, this protection shall cease to apply if, subsequent to the completeness determination, the applicant fails to submit by the deadline specified in writing by the Department any additional information needed to process the application. Monitoring, recordkeeping, and reporting for this condition consist of the application submittal.

**Conditions 79 – 83, General Compliance Requirements**

**Legal Basis:** These conditions ensure compliance with the applicable requirement in 18 AAC 50.326(j). The Permittee is required to comply with these conditions set out in 18 AAC 50.345 included in all operating permits. 40 C.F.R. 70 Appendix A documents that EPA fully approved the Alaska operating permit program effective November 30, 2001.

**Factual Basis:** These conditions for compliance are required for all operating permits.

## Conditions 84 - 85, Permit Shield

**Legal Basis:** These conditions ensure compliance with the applicable requirement in 18 AAC 50.326(j) and apply because the Permittee has requested that the Department shield the source from the non-applicable requirements listed in Table F under the federally approved State operating permit program effective November 30, 2001, as updated November 9, 2008.

**Factual Basis:** Table F of Operating Permit No. AQ0182TVP02 shows the permit shields that the Department granted to the Permittee. The following table shows the requests that were denied and the reasons that they were denied. The Department based the determinations on the permit application, past operating permit, construction permits and inspection reports.

### Table L – Permit Shields Denied

| Shield Requested: | Reason for Shield Request: | Reason for Request Denial: |
|---|---|---|
| 18 AAC 50.045(b) – Prohibitions | The permit implements all applicable air quality requirements for the stationary source. Since compliance with the permit will constitute compliance with applicable local, state, or federal air quality laws, this requirement is not applicable to the stationary source. | These prohibitions are ongoing requirements and therefore cannot be shielded. The prohibitions have not been placed in the permit because they add no value to the permit with respect to controlling stationary source emission units. These prohibitions remain in effect because they are in regulation whether they appear in the stationary source operating permit or not. Shielding the applicant from subparagraph (b), for instance, would have the effect of shielding the applicant from all requirements contained in the Air Quality Control Regulations including the requirement to obtain a permit if the shield requested is granted. |
| 18 AAC 50.045(c) – Prohibitions | This requirement will be implemented through 18 AAC 50.201, which is otherwise addressed in the permit. This requirement is not applicable because the Department will impose any special requirements to protect ambient air quality through permit conditions adopted under 50.201. | |
| 18 AAC 50.201 – Ambient Air Quality Investigation | This requirement is not applicable until such time as the Department requests an ambient air quality investigation. | This requirement remains in effect because it is in regulation whether it appears in the stationary source operating permit or not. |
| 40 C.F.R. 63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines | GC #1 is not a major source of HAPs. The area source provisions of this rule do not apply to existing engines (those constructed, modified, and reconstructed prior to June 12, 2006). | The new revision to the rule dated March 10, 2010 (effective May 2010) provided requirements for existing stationary RICE. Therefore, area sources are no longer exempt from this rule. |

## Attachment A

**Figure 1. Summary Report - Gaseous and Opacity Excess Emission and Monitoring System Performance**

Pollutant (Circle One—$SO_2$/NOx/fuel sulfur)

Reporting period dates:

From ___________ to ___________

Company: ______________________________

Emission Limitation: ______________________________

Address: ______________________________

Monitor Manufacturer and Model No.: ______________________________

Date of latest CMS (CEMS and PEMS) Certification or Audit: ______________________________

Process Unit(s) Description: ______________________________

Total source operating time in reporting period[1]: ______________________________

| Emission Data Summary[1] | CMS (CEMS and PEMS) Performance Summary[1] |
|---|---|
| 1. Duration of excess emissions in reporting period due to: | 1. CMS (CEMS and PEMS) downtime in reporting period due to: |
| a. Startup/shutdown ________ | a. Monitor equipment malfunctions ________ |
| b. Control equipment problems ________ | b. Non-Monitor equipment malfunctions ________ |
| c. Process problems ________ | c. Quality assurance calibration ________ |
| d. Other known causes ________ | d. Other known causes ________ |
| e. Unknown causes ________ | e. Unknown causes ________ |
| 2. Total duration of excess emission ________ | 2. Total CMS (CEMS and PEMS) Downtime ________ |
| 3. Total duration of excess emissions X (100)/[Total source operating time] ________ %[2] | 3. [Total CMS (CEMS and PEMS) Downtime] X (100)/[Total source operating time] ________ %[2] |

[1] For opacity, record all times in minutes. For gases, record all times in hours.
[2] For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS (CEMS or PEMS) downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in this condition shall be submitted.

On a separate page, describe any changes since last quarter in CMS, process or controls.

I certify that the information contained in this report is true, accurate, and complete.

______________________________
Name

______________________________
Signature