Alaska Department of Environmental Conservation
Air Permits Program

Public Comment - May 20, 2013
BP Exploration (Alaska), Inc.
Flow Station #2

STATEMENT OF BASIS
of the terms and conditions for
Permit No. AQ0268TVP02

Reviewed by: Jim Plosay
ADEC AQ/APP Juneau

Prepared by: Enviroplan Consulting
Permit Writer: Tanya White

INTRODUCTION

This document sets forth the statement of basis for the terms and conditions of Operating Permit No. AQ0268TVP02.

STATIONARY SOURCE IDENTIFICATION

Section 1 of Operating Permit No. AQ0268TVP02 contains information on the stationary source as provided in the Title V permit application.

The stationary source is owned by BP Exploration (Alaska) Inc., ConocoPhillips Alaska, Inc., Chevron USA, Inc. and ExxonMobil Alaska Production, Inc., and 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 is 1311 – Crude Petroleum and Natural Gas Production. The NAICS code for this stationary source is 211111.

Decision

FS#2 is located within the Prudhoe Bay Unit (PBU) on the North Slope of Alaska. The Department has determined that the surface structures with their associated emission units located on the FS#2 production pad and emissions units located on PBU drill sites (DS) 3, 4, 9, 11, 16, and 17 are to be aggregated to create a single stationary source. The Grind & Inject Facility is located on Pad 4 and has its own Title V operating permit AQ0168TVP02. Since it is co-located, it is considered part of the FS#2 stationary source by the Department. This determination applies to both the State's Title I and Title V air quality permitting programs.

Currently, the significant emission units at the FS#2 and the Grind and Inject Facility sites for Title V purposes are those identified in "Table A" of the two respective operating permits AQ0268TVP02 and AQ0168TVP02. In addition, insignificant emission units are located at these sites. 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 drill sites under AQ0455TVP02 (BPXA Transportable Drill Rigs). Operation of such emission units is considered a temporary construction activity as long as they are not located and operated (continuously or intermittently) at the same drill site for more than 24 consecutive months. The 24-month clock is reset each time these emission units are moved from drill site to drill site, even if the new physical location is at a drill site governed by the same permit as the previous drill site 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 Department 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, the Department has used the concept of the common sense notion of a plant to inform proximity. In its analysis, the Department has developed what is referred to as the "wagon wheel" model based on the production centers (hubs) and drill sites (spokes). In this model of the plant, the drill sites 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 Co.

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 the Department 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 Prudhoe Bay Unit, 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 is, of course, determined by the flow of wellhead fluids (raw materials) and sales oil (finished crude). Whether a production drill site 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.

<u>Rationale for Hub and Spoke Aggregation Model</u>

In the context of the Prudhoe Bay Unit, 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 drill sites (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, FS3, 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 shut down 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 drill sites 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 drill sites. The hub and spoke production model develops naturally from the logistics of the business.

Within this conceptual framework, the Department 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 the Department 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 the Department 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.

Other Models of Aggregation Discussed

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 Permo -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 Department 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 stationary 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 Department 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 the Department 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 drill sites 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, 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 Gathering Center #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 Department does propose combining two of the separate support facilities as part of this review of stationary sources operating at PBU. The Department 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 FS#2 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 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 drill sites created after the issuance of this permit will be evaluated on a case-by-case basis as follows.

1) Production drill sites 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 drill sites 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 drill sites, other factors will need to be considered when determining whether the drill site and its emission unit should become part of the existing stationary source.

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 Flow Station #2 that have specific monitoring, recordkeeping, and reporting requirements are listed in Table A of Operating Permit No. AQ0268TVP02.

Table A of Operating Permit No. AQ0268TVP02 contains information on the emission units regulated by this permit as provided in the permit renewal 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.

This stationary source also has an inventory of storage tanks with a storage capacity greater than 10,000 gallons. While four tanks are listed in Table A as regulated tanks, the following is a full listing of such storage tanks:

Table E – Inventory of Storage Tanks at Flow Station #2 with a Storage Capacity Greater than 10,000 Gallons

Tag No.	Capacity (gallons)	Service	Installation, Delivery, or Commenced Construction Date
16-1981 (EU ID 24)[c]	676,200	Produced Water Surge Tank	1989[a]
16-1982 (EU ID 25)[c]	508,200	Primary Surge Tank	1989[a]
16-1983 (EU ID 26)[c]	508,200	Primary Surge Tank	1989[a]
16-1951 (EU ID 27)[c]	440,638	Produced Water Tank	11/2/83[b]
16-1273	12,000	TEG	1975[a]

Tag No.	Capacity (gallons)	Service	Installation, Delivery, or Commenced Construction Date
16-1931	36,097	Diesel Fuel	1974[(b)], 1975[(a)]
16-1932	76,000	Glycol	1974[(b)], 1976[(a)]
16-1933	428,300	Slop Oil	1974[(b)], 1979[(a)]
16-1934	420,000	Slop Oil	1974[(b)], 1979[(a)]
16-1935	428,300	Fire Water	1978[(a)]
16-1937	134,988	Produced Water	1974[(b)], 1976[(a)]
16-1938	21,000	Skim Oil	1974[(b)], 1976[(a)]
16-1961	20,874	Corrosion Inhibitor	1982[(a)]
16-1984	184,000	Skim Oil	1989[(a)]
27-1902-1 (at DS3)	84,000	Methanol/Water	1982[(a)]
27-1902 (at DS4)	84,000	Methanol/Water	1982[(a)]
27-1902-C (at DS9)	84,000	Methanol/Water	1981[(a)]
27-1902 (at DS11)	84,000	Methanol/Water	1982[(a)]
27-1902-TNK (at DS16)	84,000	Methanol/Water	1982[(a)]
27-1902-TNK (at DS17)	84,000	Methanol/Water	1982[(a)]

Notes:

(a) Installation date.
(b) Commenced construction date.
(c) Tanks 16-1981 (EU ID 24), 16-1982 (EU ID 25), 16-1983 (EU ID 26), and 16-1951 (EU ID 27) are included in Table A of Permit No. AQ0268TVP02.

EMISSIONS

A summary of the potential to emit (PTE)[1] and assessable PTE, as indicated in the permit renewal application submitted by BP Exploration (Alaska) Inc. for the Flow Station #2 production facility and drill sites and verified by the Department, is shown in the table below.

Table F - Emissions Summary, in Tons Per Year (TPY)[b, f]

Pollutant	NO_X	CO	PM_{10}	SO_2	CO_2e[d, e]	VOC	HAPs[c]	Total (excluding CO_2e and HAPs)
FS#2 (Production Facility) PTE[a]	3,684	1,258	79	203	835,193	38	15.8	5,260
Drill Site PTE (excluding G&I)[i]	39	9.0	1.1	1.3	1,628	3.1	1.3[h]	53
Portable IEU Heaters[g]	9.8	2.5	0.5	10	10,513	0.2	0.5	23
Total PTE (excluding G&I)	3,733	1,269	80	214	847,335	41	17.6[h]	5,366
Assessable PTE (excluding G&I)	3,733	1,269	80	214	--	41	--	5,366

Notes:

(a) The production pad includes diesel-fired engines EU IDs 19 through 21 as well as production pad tanks, turbines, stationary heaters, and flares.

(b) Non-road engine emissions are not included since emissions from non-road engines are not used when determining the classification (major or minor) of a stationary source under AS 46.14.130 and are not included for emission fees.

(c) The PTE of each single HAP is less than 10 tons per year. HAP emissions are almost all VOCs, therefore, to avoid double counting HAP emissions are not included in the "Total" column.

(d) Greenhouse gas (GHG) means the air pollutant defined in 40 C.F.R. 86.1818-12(a) as the aggregate group of six greenhouse gases: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. The stationary source emits or has the potential to emit only CO_2, N_2O and CH_4.

(e) CO_2e or carbon dioxide equivalent emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its global warming potential (GWP). Total GHG CO_2e calculations submitted by the Permittee on August 22, 2011 were provided in units of metric tons (tonnes). The GHG emissions shown here are in units of short tons.

(f) Emissions are based on calculations submitted by the Permittee on August 22, 2011 and May 1, 2013.

(g) One seventh of the total estimated emissions from all portable IEU heaters used throughout the Greater Prudhoe Bay (GPB) are summarized here. Since the portable IEU heaters are used throughout the Greater Prudhoe Bay field, the total emissions have been split equally among the seven GPB production facilities (LPC, GC-1, GC-2, GC-3, FS#1, FS#2, and FS#3. An aggregated value at any individual drill site or production facility is unknown and varies considerably.

(h) HAP emissions from a typical drill site associated with FS#2 are summarized here. Drill site emissions are not aggregated with each other or with the production pad when determining the HAP major source status of the source (see discussion below).

(i) The drill site PTE includes emissions from diesel-fired engines EU IDs 28 through 33 and tanks located at the sites. Drill site PTE is based on a maximum annual operating time of 500 hours per year as suggested by EPA in the September 6, 1995 memo authored by John S. Seitz titled "Calculating PTE for Emergency Generators".

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[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.

Table G - Emissions Summary, in Tons Per Year (TPY) - Grind and Inject Facility[2]

Pollutant	NO_X	CO	PM_{10}	SO_2	VOC	HAPs	Total (excluding CO_2e and HAPs)
PTE	16.1	13.5	1.2	4.0	0.9	<1	35.8
Assessable PTE	16	14	1	4	1	--	36

Table H - Emissions Summary, in Tons Per Year (TPY) - TDRs[3]

Pollutant	NO_X	CO	PM_{10}	SO_2	VOC	HAPs	Total (excluding CO_2e and HAPs)
PTE (all emission units)	198.1	50.3	8.1	20.8	7.5	--	285
PTE (nonroad engines excluded)	12.5	3.1	1.25	20.8	0.21	--	38
Assessable PTE	198	50	--	21	--	--	278

The total PTE for this aggregated stationary source becomes:

Table I – Emission Summary, in Tons Per Year (TPY) – Total Stationary Source

Pollutant	NO_X	CO	PM_{10}	SO_2	CO_2e	VOC	HAPs	Total (excluding CO_2e and HAPs)
PTE	3,949	1,333	89	239	847,335	50	18	5,660
Assessable PTE for FS#2	3,949	1,333	89	239	--	50	--	5,660

The assessable PTE listed under Condition 43.1 is the sum of the emissions of each individual air pollutant other than CO_2e for which this portion of stationary source has the potential to emit quantities greater than 10 TPY. The emissions listed in Table F are estimates to be used for informational purposes only. The listing of the emissions does not create an enforceable limit to the stationary source.

The PTE for criteria pollutants was estimated based on AP-42 emission factors current as of the date of the permit renewal application submittal, source test results, vendor supplied emission factors, any allowable emission rates and limits, and/or operational limits applicable to emission units at the stationary source. Potential emissions of SO_2 are estimated based on mass balance and 0.11% sulfur content by weight in the liquid fuel, 200 ppmv H_2S in the fuel gas fired by

[2] Emissions are based on calculations submitted by the Permittee on August 22, 2011.

[3] From AQ Title V Operating Permit AQ0455TVP01 Rev.3 of October 6, 2010.

turbines EU IDs 3, 4, and 7 and flares EU IDs 22 and 23, and 140 ppmv H_2S in the fuel gas for EU IDs 1, 2, 5, 6, and 8 through 18.

For Greenhouse Gas (GHG) emissions calculations were submitted by the Permittee on August 22, 2011. PTE for carbon dioxide equivalent (CO_2e) was estimated based on emission factors found in 40 C.F.R. 98, Subpart C, Tables C-1 and C-2.

The HAP emissions shown in Table F are the total HAP PTE for all regulated emission units at all aggregated FS#2 locations that define the stationary source. However, per 40 C.F.R. 71.2, emissions from oil or gas exploration or production wells with their associated equipment are not aggregated when determining the total potential to emit hazardous air pollutants. Therefore, emissions from units located at drill sites, including the Grind & Inject Facility located at Drill Site 4, are not aggregated with each other or with emissions from units at the production pad when determining the HAPs major status of the stationary source.

Emissions of HAPs were calculated using GRI-HAPCalc Version 3.01 software, AP-42 emission factors, and Ventura County Air Pollution Control District (VCAPCD) emission factors for combustion units. Tank HAP emissions were estimated using TANKS v.09d. Each individual HAP has a PTE less than 10 TPY; and the combined HAPs for the FS#2 stationary source are less than 25 TPY. The total HAPs from all drill sites, grind and inject operations, portable IEU heaters, and the production pad that make up Flow Station #2 stationary source are approximately 17 TPY. The highest individual HAP is formaldehyde with an emission rate of approximately 4 TPY.

Based on these findings, FS#2 is not a major source of HAP emissions since the calculated HAP emissions are less than the triggers of 10/25 TPY.

HAP emissions are a subset of VOC emissions, so they are not included in the total assessable PTE.

Table G shows the potential to emit associated with emission units permitted under the BPXA Grind & Injection Facility (G&I) permit, (AQ0168TVP02) and Table H shows the potential to emit associated with emission units permitted under the BPXA Transportable Drill Rigs (TDR) permit, (AQ0455TVP01). (The TDR portion of the PTE shown in Table H includes emissions from non-road engines.) As stated in G&I (AQ0168TVP02) stationary source identification SOB discussion, the Grind and Inject Facility, FS#2, and BPXA Transportable Drill Rigs are considered by the Department as a single stationary source governed by three separate Title V Operating Permits AQ0168TVP02 (Grind and Inject Facility), AQ0268TVP02 (FS2), and AQ0455TVP02 (TDR).

BASIS FOR REQUIRING AN OPERATING PERMIT

In accordance with AS 46.14.130(b), an owner or operator of a Title V source[4] 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 stationary 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;

[4] *Title V source* means a stationary source classified as needing a permit under AS 46.14.130(b) [ref. 18 AAC 50.990(111)].

- 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 not exempted from the requirement to obtain an operating permit; 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 Clean Air 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_2e and 100 TPY GHGs on a mass basis.

AIR QUALITY PERMITS

Previous Air Quality Permit-to-Operate

The Department issued Permit-to-Operate 8936-AA009 on December 12, 1989 to install three Solar Centaur turbines under State provisions in effect at that time. The Department imposed NO_X BACT as part of the project.

The most recent permit-to-operate issued for this stationary source is Permit-to-Operate No. 9473-AA011, as amended through May 2, 1995. This permit-to-operate includes all construction authorizations issued through May 2, 1995, and was issued before January 18, 1997 (the effective date of the divided Title I/Title V permitting program).

Federal PSD Air Quality Permit

EPA Prevention of Significant Deterioration (PSD) permit numbers PSD-X80-09 and PSD-X81-13, as amended through August 29, 1997, contain specific BACT requirements for the stationary source. All stationary source -specific requirements established in these previous permits are included in the renewed Title V operating permit as described in Table J.

Title I (Construction and Minor) Permits

The Department issued Minor Permit No. AQ0268MSS02 to this stationary source effective on April 22, 2013. The permit revised the fuel H_2S limits, and added operational limits to protect ambient air SO_2 standards. The Department established stationary source-specific requirements in this Title I permit that are included in this operating permit renewal as described in Table M.

Title V Operating Permit Application, Revisions and Renewal History

The Permittee submitted an application for the initial FS#2 Title V Operating Permit on December 4, 1997. The Department issued Operating Permit No. AQ0268TVP01 effective October 20, 2003.

On February 17, 2004, the Department revised the operating permit to add additional drill sites to the stationary source in response to a petition filed objecting to North Slope determinations for another Prudhoe Bay source.

The Permittee submitted a permit renewal application on June 11, 2008.

The Department received additional information on June 30, 2011 (an amended application including NESHAP Subpart ZZZZ applicability and updated NESHAP Subpart ZZZZ permit shields, updated permit shield requests for various tanks, revised stationary source information (Section 1 of this permit), GHG calculations and revised criteria pollutant/HAP PTEs).

The Department received additional information on August 22, 2011 (an amended application including GHG calculations and revised criteria pollutant/HAP PTE calculations). Further updates from changed Federal rules was submitted by BPXA on April 30, 2013. Finally the Department is treating AQ0268MSS02 issued on April 22, 2013 as a supplement to the renewal application and incorporating those terms as currently applicable requirements.

COMPLIANCE HISTORY

The stationary source has operated at its current location since 1975. Review of the permit files for this stationary source, which includes the past inspection reports, indicates a stationary source that is generally operating in compliance with its operating permit.

In the Full Compliance Evaluation conducted for the period January 1, 2006 through December 31, 2007, the Department found FS#2 to be non-compliant with Conditions 28, 36, and 64 of Permit No. AQ0268TVP01. The violations were addressed by BPXA and no further actions were required at that time.

In the Full Compliance Evaluation conducted for the period January 1, 2008 through December 31, 2009, the Department found FS#2 to be non-compliant with Conditions 21.1a, 36, and 64 of Permit No. AQ0268TVP01. Such actions are in violation of 18 AAC 50.040(a)(2)(V), 50.040(b)(3), 50.345(c), AS 46.14.010, and AS 46.14.120(c). The Department also determined that the violations are not ongoing and BPXA has submitted deviation reports outlining the corrective actions taken to minimize the potential for a reoccurrence.

An Excess Emissions and Permit Deviation Form was submitted by BPXA on April 30, 2010. The excess emissions/permit deviation was discovered April 21, 2010 and the event/deviation began on October 20, 2008. The permit deviation occurred for Condition 20.1b(1)(B)(2) of Permit No. AQ0268TVP01 for turbines EU IDs 8 through 12. According to BPXA, in dialogue with ADEC inspectors during a Full Compliance Evaluation for FS#2, BPXA discovered that source tests for the Centaur 40 and Centaur 50 turbines were required to occur once during the term of the air operating permit. The turbine models were tested 9 days and 11 days prior to issuance of the air permit, respectively. The compliance authority misinterpreted the permit condition, and would have tested 2 weeks later had the implications been known. As a preventive action, BPXA has communicated lessons learned from this experience to other BPXA compliance authorities.

APPLICABLE REQUIREMENTS CARRIED FORWARD FROM PRE-CONSTRUCTION PERMITS

Incorporated by reference at 18 AAC 50.326(j), 40 C.F.R. Part 71.6 defines “applicable requirement” to include the terms and conditions of any pre-construction permit issued under rules approved in Alaska’s State Implementation Plan (SIP) and any pre-construction permits issued by the EPA.

Alaska’s SIP 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 18, 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 emission unit- or 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.

Title V Operating/Construction Permit No. AQ0268TVP01 included all construction authorizations issued through October 20, 2003, and was issued after January 18, 1997 (the effective date of the divided Title I/Title V permitting program). Permit No. AQ0268TVP01 revised and rescinded specific terms and conditions of Permit-to-Operate No. 9473-AA011 and carried forward applicable stationary source-specific terms and conditions of the permit-to-operate. Details pertaining to the revisions made by Permit No. AQ0268TVP01 to Permit No. 9473-AA011 are included beginning on page 12 and ending on page 21 of the Statement of Basis to Permit No. AQ0268TVP01, including Tables C through G of that document. Amended language originally from pages 12 through 21 of the Statement of Basis to Permit No. AQ0268TVP01 are included following Table J below. The only other pre-construction permits that apply to this stationary source are EPA PSD permit Nos. PSD-X80-09 and PSD-X81-13, amended August 29, 1997, and Permit-to-Operate 8936-AA009. The State’s 1989 permit was subsumed into Permit-to-Operate 9473-AA011 and the operating/construction permit.

Table J below lists the emission unit and source-specific requirements carried forward from Permit-to-Operate No. 9473-AA011 and Operating/Construction Permit No. AQ0268TVP01 into Operating Permit No. AQ0268TVP02 and documents how/if the condition carried forward was revised compared to the previous permits. Table M below lists the emission unit and source-specific requirements carried forward from Minor Permit No. AQ0268MSS02 into Operating Permit No. AQ0268TVP02 and documents how/if the condition carried forward was revised compared to the previous permits. Table J and Table M do not include standard and general conditions.

Table J - Comparison of Previous Permit-to-Operate No. 9473-AA011 (5/2/95 amendment) and Operating/Construction Permit No. AQ0268TVP01 Conditions to Operating Permit No. AQ0268TVP02 Conditions[5]

Permit No. 9473-AA011 Condition Number	Description of Requirement	Permit No. AQ0268TVP01 Condition No.	Permit No. AQ0268TVP02 Condition Number	How condition was revised
Exhibit A	Emission Unit Inventory	Section 3	Section 2	Updated the emission inventory based on new information in the permit renewal application/application amendments.
2 and Exhibit B	Visible Emissions Standards	3	1	Effective 9/13/07, the EPA approved certain changes to the SIP limits, including removal of the "more than 3 minutes in any one hour criterion". The approval eliminated the need for the footnotes found in AQ0268TVP01 in association with these conditions and allows the deletion of the "3-minute" criterion. In AQ0268TVP02, the "6-minute" 20% visible emissions limit was consolidated into one condition statement. Presentation of the BACT 10% opacity limit carried forward from EPA permit PSD-X80-09 is unchanged.
2 and Exhibit B	Permittee shall comply with the most stringent of applicable emission standards and specifications set out in Exhibit B.	3 and 4	1 through 8	The Alaska SIP limits have been carried forward with amendments. The apparent increase in the number of applicable conditions is a result of reorganization of the monitoring, recordkeeping, and reporting requirements in the new permit template. Other limits have been carried forward without change. BACT limits are from EPA PSD permits PSD-X80-09 (PSD II) and PSD-X81-13 (PSD IV) as revised 8/29/97 and the 1989 ADEC BACT.

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

Permit No. 9473-AA011 Condition Number	Description of Requirement	Permit No. AQ0268TVP01 Condition No.	Permit No. AQ0268TVP02 Condition Number	How condition was revised
4 and Exhibit C	Permittee shall conduct a monthly test of the fuel gas to determine the sulfur (H_2S) content of the gas burned in the turbines and heaters.	5.1, 21.1	9.1, 29.4	Similar updated provisions.
5 and Exhibit C	Permittee shall conduct a test of the fuel oil to determine sulfur content of the liquid fuel burned in the equipment.	5.2	9.6	Similar updated provisions.
6 and Exhibit D	Permittee shall calculate the total quantity of sulfur dioxide from the stationary source each month and report the result in the operating report.	None	None	Condition has been deleted. Reason for original permit condition is no longer valid. Potential increase of fuel gas sulfur content not considered a PSD modification.
4, 5, and 6	Fuel gas and oil sulfur testing, recordkeeping, and reporting requirements	5	9	Similar updated provisions.
Exhibit B	Turbine BACT limits	6 and Table 2	10 and Table B	Except for SO_2, no change to the limits or to the periodic MR&R for NO_X emissions. Added requirements for periodic MR&R for CO, PM, and opacity. The Department incorrectly included Footnote Nos.2 and 3 of Table 2 (BACT Emission Limits) of Construction/Operating Permit AQ0268TVP01 issued October 20, 2003 that stated that the BACT limits in the tables apply only to full load. These footnotes were not part of the original BACT limits in the EPA permits PSD-X80-09 and PSD-X81-13. As such, Footnote Nos. 2 and 3 of Table 2 (AQ0268TVP01) were not carried forward into AQ0268TVP02. The Department did include the footnote from the Tables that comprise Attachment 2 and 4 of EPA Permit PSD-X-81-13 adjusted for the current Y-value.

Permit No. 9473-AA011 Condition Number	Description of Requirement	Permit No. AQ0268TVP01 Condition No.	Permit No. AQ0268TVP02 Condition Number	How condition was revised
Exhibit B	Fuel Gas Sulfur Content Limit for EU ID 7	7	10 and Table B	Minor Permit No. AQ0268MSS02, effective 4/22/13, revised the H_2S fuel gas limit from 30 ppm to 200 ppm. See Table K for additional information.
Exhibit B	Fuel Sulfur Content Limits	7	11	Minor Permit No. AQ0268MSS02, effective 4/22/13, revised the H_2S fuel gas limits for EU ID 7 and add H_2S fuel gas limits for EU IDs 1-6, 8-18, 22, and 23. Additionally, the liquid fuel sulfur content limits were added to Condition 11 for EU IDs 19-21 and 28-33. See Table L for additional information.
Exhibit B	Operating Hours Limit for Gas Turbines for EU IDs 1 and 2	8	13	Similar updated provisions.
Exhibit B	Operating Hours Limit for EU IDs 19 through 21	9	14	Similar updated provisions.
Exhibit D, Item 3	Hours of Operation Monitoring for EU IDs 1 through 21 and 28 through 33	10	15	Similar updated provisions.
Condition 7, Exhibit C, and Exhibit D, Item 3	Fuel Consumption Monitoring for EU IDs 1 through 23 and 28 through 33	11	16	EU IDs 28 through 33 were added to condition. Similar updated provisions.
None	Owner Requested Limit For EU IDs 24 through 26. Permittee shall install, maintain, and operate a closed vent system and control device.	None	17	During this review, the Permittee requested Condition 17 be added to the permit, which states that the Permittee must install, maintain, and operate a closed vent system and control device meeting the specifications of 40 C.F.R. 60.112b(a)(3) for EU IDs 24 through 26. This condition was requested to avoid applicability of NSPS Subpart Kb for EU IDs 24 through 26.
None	NSPS Subpart A Excess Emissions and Monitoring Systems Performance Report	13	22	Revised to make reporting consistent with the custom fuel monitoring schedule dated October 18, 1993 and specific to NSPS Subpart GG monitoring requirements.

Permit No. 9473-AA011 Condition Number	Description of Requirement	Permit No. AQ0268TVP01 Condition No.	Permit No. AQ0268TVP02 Condition Number	How condition was revised
None	NSPS Subpart GG Fuel Sulfur Monitoring and Reporting	21	30	Revised to include the EPA-approved NSPS Subpart GG Fuel Sulfur Monitoring Requirements (as of July 8, 2004 revision) with revisions as allowed under EPA-approved October 2, 1997 alternate H_2S sampling method and the July 13, 1993 custom fuel monitoring schedule (with additional clarifications given in correspondence dated 8/20/93, 10/18/93, and 8/19/96). In addition, the permit has been revised to include the provision for an annual reporting frequency as stated in the October 18, 1993 EPA letter.
None	40 C.F.R. 63 Subparts A and ZZZZ	None	31, 32, 33, 34, 35,	Added the applicable requirements of 40 C.F.R. 63 Subpart ZZZZ and associated 40 C.F.R. 63 Subpart A requirements, which apply to EU IDs 19 through 21 and 28 through 33.
17	Permittee shall submit a showing of compliance with 18 AAC 50.110.	None	None	Condition was rescinded on 5/2/95.
Exhibit D, Items 4 and 5	Permittee shall report the high, low, mean, and standard deviation of the fuel gas H_2S and liquid fuel sulfur content annually.	None	None	Condition has been deleted. The Department no longer requires this information.

Table M - Comparison of Previous Minor Permit No. AQ0268MSS02 to Operating Permit No. AQ0268TVP02 Conditions[6]

Permit No. AQ0268MSS02 Condition Number	Description of Requirement	Permit No. AQ0268TVP02 Condition Number	How condition was revised
7	Operating Hour Limits and MR&R Requirements for EU IDs 19, 20, and 21	14	Same requirements
8	Liquid Fuel Sulfur Content Limit of 0.11 %wt and MR&R Requirements	11	Same requirements
9	Fuel Gas H_2S Concentration Limit and MR&R Requirements for EU IDs 1 through 18 and 22, and 23	11	Same requirements
10	H_2S/SO_2 BACT Limits for Turbine EU ID 7	10	Same requirements
11	Owner Requested Limits on Operating Hours for EU IDs 1 and 2	13	Same requirements
12	PSD Applicability Requirements – MR&R for Annual SO_2 Emissions from Fuel Gas Combustion	12	Same requirements

REVISIONS MADE TO AIR QUALITY PERMIT-TO-OPERATE 9473-AA011 IN OPERATING PERMIT AQ0268TVP01

The previous operator of FS#2 (ARCO Alaska) submitted a construction permit application under provisions of the former 18 AAC 50.305(a)(3) requesting modifications of the terms and conditions of Operating Permit No. 9473-AA011. Under the provisions of 18 AAC 50.305(a)(3), the owner or operator of a stationary source may request Department approval in a construction permit to revise or rescind conditions of a permit issued under former 18 AAC 50.400. Operating Permit No. 9473-AA011 was issued under former 18 AAC 50.400. BPXA submitted the application to revise or rescind existing permit conditions that are either: 1) in error; 2) do not correctly reflect applicable requirements; 3) are out dated; or 4) are otherwise inappropriate.

On December 4, 1997, ARCO Alaska, Inc. (ARCO) submitted a construction permit application requesting revisions to Operating Permit No. 9473-AA011, along with the Title V operating permit application, for FS #2. ARCO was the operator of the stationary source in 1997 so the application was submitted under the name ARCO. BPXA is the current operator of FS #2, and the application has been transferred to its name. BPXA will be identified as the applicant for the remainder of this document. BPXA proposed that terms and conditions in the old operating permit be updated and made identical with PSD permit numbers PSD-X80-09 and PSD-X81-13, amended August 29, 1997 by the EPA.

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

In 1980 and 1981, EPA Region 10 issued PSD permit numbers PSD-X80-09 (PSD II) and PSD-X81-13 (PSD IV) to BPXA [actually Atlantic Richfield and Sohio Petroleum Companies, the field operators at that time] for construction of new equipment at eight Prudhoe Bay stationary sources. BPXA worked with EPA to clarify and revise emission limits in the EPA PSD permit. The Department has been copied on all correspondence with Region 10 in this regard. This effort resulted in issuance of PSD revisions by EPA on August 29, 1997. The permit revisions were included with the Permittee's application for AQ0268TVP01. The primary revisions included identification of specific equipment and tag number, apportionment of field-wide ton per year limits to stationary source–specific equipment group limits, and updated emission limits based solely on AP-42 factors to the values in the edition of AP-42 that were current in 1997.

EPA permitted four turbines (Tag Nos. NGT-16-1803, NGT-16-1804, NGT-16-15105, and NGT-16-15106) during the 1980 PSD review (PSD II) and one turbine (Tag No. NGT-16-15133) during the 1981 PSD review (PSD IV) for FS#2. Except for NGT-16-15133 (see discussion following paragraph below), these units have not undergone any subsequent ADEC PSD permitting and BACT determinations, and their respective emission limits should reflect exactly the limits in the August 29, 1997 revision to the EPA permit.

The construction permit application requested that each current EPA BACT emission limit be established as the current limit in the ADEC permit for the stationary source. Some Department limits were revised to accommodate this request, or a new emission limit was established if the 1997 EPA permit indicated that no limit applies. The EPA revision of PSD II established emission limitations for individual turbines. BACT emission limits apply for NO_X, CO, and PM to four turbines (Tag Nos. NGT-16-1803, NGT-16-1804, NGT-16-15105, and NGT-16-15106) in terms of tons per year as well as other terms (*e.g.*, ppmv or lb/MMBtu). Visible emission limits were also established in terms of percent opacity.

The EPA revision of PSD IV established emission limitations for individual turbines. BACT emission limits apply for NO_X and CO to one turbine (Tag No. NGT-16-15133) in terms of tons per year as well as other terms (*e.g.*, ppmv or lb/MMBtu), and only in terms of tons per year for PM and SO_2. Visible emission limits were also established in terms of percent opacity. The August 29, 1997 revision to the PSD-X81-13 permit does not specifically identify a fuel gas H_2S limit for this turbine (EU ID 7). However, EPA's preliminary determination analysis document, dated July 1, 1981, for the original PSD IV permit does identify a fuel gas H_2S level, which was used to establish the BACT ton per year limit. The ton per year limit presented in the August 29, 1997 permit revision is based on an annual average fuel gas H_2S content of 30 ppmv. As such, a fuel gas H_2S limit of 30 ppmv was carried forward from Permit 9473-AA011 into AQ0268TVP01 based on the fuel gas H_2S concentration used to establish the annual EPA ton-per-year BACT SO_2 limit, after revision by the Department. This notwithstanding, as a result of fuel gas souring, on April 19, 2012 BPXA submitted a request to increase the fuel gas H_2S limit for NGT-16-15133 from 30 ppmv to 200 ppmv; and this revised limit is incorporated to AQ0268TVP02.

Permit No. 9473-AA011 indicates that each value in Exhibit B is either an emission limit or an estimate. As requested in the application, the vast majority of these limits should be identified as emission estimates only. The only exceptions are the turbines with EPA BACT determinations and equipment permitted under the Department's PSD determination.

On June 27, 1985, two Solar turbines (Tag Nos. NGT-16-15401 and NGT-16-15402) were permitted by the Department. This permit was not a PSD review. Instead, the Department allowed an exchange of equipment previously permitted through PSD review by EPA. The permit allowed the installation of two 4,000 Hp Solar Centaur turbines in exchange for deleting one permitted but never constructed 36,000 Hp turbine (originally permitted under EPA PSD II) and one 5,000 Hp turbine (originally permitted under EPA PSD IV). When the Department issued the permit in 1985, the permit carried forward the short-term NO_X and CO BACT limits for these turbines but did not include ton per year emission limits. Since the exchanged units were much smaller than the originally permitted units and, therefore, potential emissions from the exchanged units were much lower, it was not necessary to carry the ton per year limits forward. BPXA requested that the current NO_X ton per year limit be removed because it is not a BACT limit and the CO emission limit be changed to 0.17 lb/MMBtu to reflect the value in AP-42 that was current in 1997. This was the same CO emission limit applied to all turbines by the EPA in the PSD permit revision of August 29, 1997. Because of the considerable decrease in permitted horsepower for these two turbines, the requested change in the CO emission rate did not increase emissions above those that were originally established as BACT.

On December 12, 1989, the Department permitted three Solar turbines (Tag Nos. NGT-16-15403, NGT-16-15404, and NGT-16-15405). PSD review for these units was triggered only for NO_X. ADEC BACT requirements for these turbines applied only to NO_X on a short-term emissions limit basis. The Department did not establish a BACT ton per year limit for NO_X. These three Solar turbines should continue to have the ADEC BACT NO_X emission limits.

BPXA requested that, with the exception of source tag no. NGT-16-15133 which does have a fuel gas H_2S limit under PSD IV, any current emission limit or fuel specification limiting the concentration of H_2S or sulfur in fuel should be changed to an emission estimate. The Department established a fuel sulfur limit in natural gas at FS#2 in 1989 of 25ppm H_2S, but the basis for this limit is unclear. BPXA will continue to monitor sulfur content of fuels used at FS#2.

<u>Equipment emission limits requested by BPXA</u>. In the combined construction/operating permit AQ0268TVP01, all emission limitations were listed as annual average unless otherwise noted, since SO_2 modeling was not documented in the TAR. The basis of this limit is not to protect SO_2 standards or increments. Since potential SO_2 emissions at 25ppm H_2S did not approach 40 tons per year, the limit overreaches that necessary to avoid SO_2 PSD at 40 tons per year. All turbine NO_X emission limits and estimates referred to full load, ISO conditions. All other emission limits and estimates referred to standard conditions.

Note that for Federal limits, the Department is now reconsidering BPXA's requested limits. See condition-specific factual and legal bases for AQ0268TVP02 to follow this section.

Table N through Table Q below identify and explain the revisions made in AQ0268TVP01 to Permit-to-Operate No. 9473-AA011.

Table N – Emission Units: Turbines: GE LM 1500 [NGT-16-1801 & NGT-16-1802], GE MS 5352B [NGT-16-1803 & NGT-16-1804], Ruston TB 5000 [NGT-16-15105, NGT-16-15106, & NGT-16-15133], Solar Centaur [NGT-16-15401 & NGT-16-15402], and Solar Centaur Type H [NGT-16-15403, NGT-16-15404, & NGT-16-15405]

Pollutant	Emission Unit(s)	Limits in Permit-to-Operate 9473-AA011	AQ0268TVP01 Revised Limits[7] for Each Unit	Explanation
NO_X	GE LM 1500 (EU IDs 1 & 2)	No limit	No limit	Units are pre-PSD. No BACT or other limit applies.
	GE MS 5352B (EU IDs 3 & 4)	150(14.4/Y) ppmvd @ 15% O_2, and 862 TPY, each unit	173 ppmvd @ 15% O_2 and 1,115 TPY	EPA PSD-X80-09, 8/29/97 permit revisions; sources are also subject to the NSPS GG NO_X standard, which is the same limit.
	Ruston TB5000 (EU IDs 5 through 7)	150(14.4/Y) ppmvd @ 15% O_2 and 121 TPY, each unit	154 ppmvd @ 15% O_2 and 141 TPY	EPA PSD-X80-09 & PSD-X81-13, 8/29/97 permit revisions.
	Solar Centaur (EU IDs 8 & 9)	150(14.4/Y) ppmvd @ 15% O_2 and 121 TPY, each unit	164 ppmvd @ 15% O_2	Limit carried forward in 1985 by ADEC for exchanged PSD permitted units; ADEC BACT did not establish a ton per year limit; emission units are also subject to the NSPS GG NO_X standard, which is the same limit.
	Solar Centaur Type H (EU IDs 10 through 12)	125 ppmvd @ 15% O_2 and 99.4 TPY, each unit	125 ppmvd @ 15% O_2 and 176 ppmvd @ 15% O_2	125 ppmvd was the result of 1989 ADEC BACT; ADEC BACT did not establish a ton per year limit; sources are also subject to NSPS GG NO_X standard.
CO	GE LM 1500 (EU IDs 1 & 2)	No limit	No limit	Units are pre-PSD. No BACT or other limit applies.
	GE MS 5352B (EU IDs 3 & 4)	109 lb/MMscf, each unit	0.17 lb/MMBtu and 269 TPY	EPA PSD-X80-09, 8/29/97 permit revision.
	Ruston TB5000 (EU IDs 5 through 7)	109 lb/MMscf, each unit	0.17 lb/MMBtu and 38 TPY	EPA PSD-X80-09 & PSD-X81-13, 8/29/97 permit revisions.

[7] These limits do not include applicable Alaska SIP limits, unless otherwise specified.

Pollutant	Emission Unit(s)	Limits in Permit-to-Operate 9473-AA011	AQ0268TVP01 Revised Limits[7] for Each Unit	Explanation
	Solar Centaur (EU IDs 8 & 9)	109 lb/MMscf, each unit	0.17 lb/MMBtu	Limit carried forward in 1985 by ADEC for exchanged PSD permitted units. Original EPA PSD permit limit was based on AP-42. New limit is based on 1997 edition of AP-42 (Table 3.2-1), which applies to compressor turbines. EPA granted an identical change in the 8/29/97 revision to the EPA PSD CO BACT limits. A demonstration was made at that time to show that the total permitted turbine group potential emissions did not increase as a result of the new limit.
	Solar Centaur Type H (EU IDs 10 through 12)	109 lb/MMscf, not to exceed 400 lb/MMscf at less than rated capacity and actual operating conditions, each unit	No limit.	No ADEC BACT limit established for CO for these emission units.
Opacity	GE LM 1500 (EU IDs 1 & 2)	20%, 3 min/hr	20%, 3 min/hr and 20%, consecutive 6-min. average	Opacity standards set by AK SIP limits.
	GE MS 5352B (EU IDs 3 & 4)	20%, 3 min/hr for Source ID 3 10 %, 3 min/hr and 20%, 3 min/hr for Source ID 4	10%, consecutive 6-minute average	EPA PSD-X80-09, 8/29/97 permit revision.
	Ruston TB5000 (EU IDs 5 through 7)	10 %, 3 min/hr and 20%, 3 min/hr		EPA PSD-X80-09 & PSD-X81-13, 8/29/97 permit revisions.
	Solar Centaur (EU IDs 8 & 9)	10 %, 3 min/hr and 20%, 3 min/hr	20%, 3 min/hr and 20%, consecutive 6-min. average	No BACT or other limit applies, except for opacity standards set by AK SIP limits.
	Solar Centaur Type H (EU IDs 10 through 12)	10 %, 3 min/hr and 20%, 3 min/hr		

Pollutant	Emission Unit(s)	Limits in Permit-to-Operate 9473-AA011	AQ0268TVP01 Revised Limits[7] for Each Unit	Explanation
PM	GE LM 1500 (EU IDs 1 &2)	No limit	0.05 grains/dscf (3-hr avg.)	Units are pre-PSD. No BACT or other limit applies, except for AK SIP limit [18 AAC 50.055(b)(1)].
	GE MS 5352B (EU IDs 3 & 4)	No limit	0.014 lb/MMBtu and 22 TPY	EPA PSD-X80-09, 8/29/97 permit revision.
	Ruston TB5000 (EU IDs 5 through 7)	No limit	0.014 lb/MMBtu and 3.2 TPY for each of Source IDs 5 & 6. 3.2 TPY for EU ID 7	EPA PSD-X80-09 & PSD-X81-13, 8/29/97 permit revisions.
	Solar Centaur (EU IDs 8 & 9)	No limit	0.05 grains/dscf (3-hr avg.)	No BACT or other limit applies, except for AK SIP limit [18 AAC 50.055 (b)(1)].
	Solar Centaur Type H (EU IDs 10 through 12)	No limit		
SO_2	GE LM 1500 (EU IDs 1 & 2)	25 ppm H_2S in fuel	No limit for H_2S in fuel for all units.	No BACT or other limit applies to fuel. No limits are necessary to manage increment given current fuel gas quality.
	GE MS 5352B (EU IDs 3 & 4)	100 ppm H_2S in fuel		
	Ruston TB5000 (EU IDs 5 through 7)	25 ppm H_2S in fuel	No limit for H_2S in fuel for EU IDs 5 and 6. 30 ppmv H_2S in fuel (annual average) and 1.2 TPY SO_2 for EU ID 7	No BACT or other limit applies to fuel. No limits are necessary to manage increment given current fuel gas quality. EPA PSD-X81-13, 8/29/97 permit revision.
	Solar Centaur (EU IDs 8 & 9)		No limit for H_2S in fuel for all units.	No BACT or other limit applies to fuel. No limits are necessary to manage increment given current fuel gas quality.
	Solar Centaur Type H (EU IDs 10 through 12)			
VOC	GE LM 1500 (EU IDs 1 & 2)	No limit	No limit	Units are pre-PSD. No BACT or other limit applies.
	GE MS 5352B (EU IDs 3 & 4)			No BACT or other limit applies.
	Ruston TB5000 (EU IDs 5 through 7)			

Pollutant	Emission Unit(s)	Limits in Permit-to-Operate 9473-AA011	AQ0268TVP01 Revised Limits[7] for Each Unit	Explanation
	Solar Centaur (EU IDs 8 & 9)			
	Solar Centaur Type H (EU IDs 10 through 12)			

Table O – Emission Units: Broach Heaters [NGH-16-1431, NGH-16-1433, NGH-16-1481, and NGH-16-1491], and BS&B Reboilers [NGH-16-2801 and NGH-16-2811]

Pollutant	Emission Unit(s)	Limits in Permit-to-Operate 9473-AA011	AQ0268TVP01 Revised Limits[8] for Each Unit	Explanation
NO_X	Broach (EU IDs 13 through 16) BS&B (EU IDs 17 & 18)	No limit	No limit	Units are pre-PSD. No BACT or other limit applies.
CO	Broach (EU IDs 13 through 16) BS&B (EU IDs 17 & 18)	No limit	No limit	Units are pre-PSD. No BACT or other limit applies.
Opacity	Broach (EU IDs 13 through 16) BS&B (EU IDs 17 & 18)	20%, 3 min/hr	20%, 3 min/hr 20%, consecutive 6 min. average	Opacity standard set by AK SIP limits [18 AAC 50.055(a)(1), 1/18/97 & 5/3/02.]
PM	Broach (EU IDs 13 through 16) BS&B (EU IDs 17 & 18)	No limit	0.05 grains/dscf (3-hr avg.)	Units are pre-PSD. No BACT or other limit applies, except for AK SIP limit [18 AAC 50.055 (b)(1)].
SO_2	Broach (EU IDs 13 through 16) BS&B (EU IDs 17 & 18)	25 ppm H_2S in fuel	No limit for H_2S in fuel.	No BACT or other limit applies to fuel. No limits are necessary to manage increment given current fuel gas quality.
VOC	Broach (EU IDs 13 through 16) BS&B (EU IDs 17 & 18)	No limit	No limit	Units are pre-PSD. No BACT or other limit applies.

[8] These limits do not include applicable Alaska SIP limits, unless otherwise specified.

Table P – Emission Units: Diesel-Fired Equipment; White Superior [EDG-16-2882], Emerson GM [EDG-16-2882-01], and Caterpillar 3306T [EDG-16-1553C]

Pollutant	Emission Unit(s)	Limits in Permit-to-Operate 9473-AA011	AQ0268TVP01 Revised Limits[9] for Each Unit	Explanation
NO_X	White Superior (EU ID 19) Emerson GM (EU ID 20) Caterpillar 3306T (EU ID 21)	No limit.	No limit.	No BACT or other limit applies.
CO	White Superior (EU ID 19) Emerson GM (EU ID 20) Caterpillar 3306T (EU ID 21)	No limit.	No limit.	No BACT or other limit applies.
Opacity	White Superior (EU ID 19) Emerson GM (EU ID 20) Caterpillar 3306T (EU ID 21)	20%, 3 min/hr	20%, 3 min/hr 20%, consecutive 6 min. average	Opacity standard set by AK SIP limit.
PM	White Superior (EU ID 19) Emerson GM (EU ID 20) Caterpillar 3306T (EU ID 21)	No limit.	0.05 grains/dscf (3-hr avg.)	No BACT or other limit applies, except for AK SIP limit [18 AAC 50.055 (b)(1)].
SO_2	White Superior (EU ID 19) Emerson GM (EU ID 20) Caterpillar 3306T (EU ID 21)	0.20% S in fuel	No limit for S in liquid fuel.	No BACT or other limit applies to fuel. No limits are necessary to manage increment given current liquid fuel quality.

[9] These limits do not include applicable Alaska SIP limits, unless otherwise specified.

Pollutant	Emission Unit(s)	Limits in Permit-to-Operate 9473-AA011	AQ0268TVP01 Revised Limits[9] for Each Unit	Explanation
VOC	White Superior (EU ID 19) Emerson GM (EU ID 20) Caterpillar 3306T (EU ID 21)	No limit.	No limit.	No BACT or other limit applies.

Table Q – Emission Units: Emergency Flares HP/IP and STV

Pollutant/ Parameter	Emission Unit(s)	Limits in Permit-to-Operate 9473-AA011	AQ0268TVP01 Revised Limits[10] for Each Unit	Explanation
Operational Limit	HP/IP (EU ID 22) STV (EU ID 23)	0.9 MMscf/day, total pilot and purge gas for both flares	No limit. Rating only.	No BACT or other limits apply which restrict the quantity of pilot and purge gas used. This rating is shown in the emission unit inventory.
NO_X	HP/IP (EU ID 22) STV (EU ID 23)	No limit.	No limit.	No BACT or other limits apply.
CO	HP/IP (EU ID 22) STV (EU ID 23)	No limit.	No limit.	No BACT or other limits apply.
Opacity	HP/IP (EU ID 22) STV (EU ID 23)	20%, 3 min/hr	20%, 3 min/hr 20%, consecutive 6 min. average	Opacity standard set by AK SIP limits.
PM	HP/IP (EU ID 22) STV (EU ID 23)	No limit.	0.05 grains/dscf (3-hr avg.)	No BACT or other limit applies, except for AK SIP limit [18 AAC 50.055 (b)(1)].
SO_2	HP/IP (EU ID 22) STV (EU ID 23)	25 ppm H_2S in the fuel 67 ppm H_2S in the fuel	No limit for H_2S in fuel.	No BACT or other limit applies to fuel. No limits are necessary to manage increment given current fuel gas quality.
VOC	HP/IP (EU ID 22) STV (EU ID 23)	No Limit.	No limit.	No BACT or other limits apply.

[10] These limits do not include applicable Alaska SIP limits, unless otherwise specified.

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 selected conditions that are not included in the permit for specific reasons.

- **NSPS Subpart K**: The requirements of 40 C.F.R. 60, Subpart K (Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced After June 11, 1973 and Prior to May 19, 1978) do not apply to tanks with tag numbers 16-1273, 16-1931, 16-1932, 16-1933, 16-1934, 16-1935, 16-1937, or 16-1938, which were constructed, reconstructed, or modified between June 11, 1973 and May 19, 1978 for the following reason(s):
  1. the vessel does not store a *petroleum liquid*, as defined in 40 C.F.R. 60, Subpart K; and/or
  2. the vessel's storage capacity is below thresholds (40,000 gallons); and/or
  3. the vapor pressure of stored liquid is below thresholds; and/or
  4. the volatile organic liquid is processed prior to custody transfer.
- **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 FS#2, 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 40 C.F.R. 68.115.
- **Compliance Assurance Monitoring (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).
- **Oil and Gas Production Facility Standards, 40 C.F.R. 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 less than 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. AQ0268TVP02. This 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 through 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 through 23 and 28 through 33 are fuel-burning equipment.

U.S. EPA incorporated these standards as revised in 2002 into the SIP effective September 13, 2007.

Factual Basis: For EU IDs 1 through 23 and 28 through 33, Condition 1 prohibits the Permittee from causing or allowing visible emissions in excess of the applicable standard in 18 AAC 50.055(a)(1). For EU IDs 3 through 7, the Permittee is additionally required to comply with a more restrictive visible emissions limit established in Permit Nos. PSD-X80-09 & PSD-X81-13, included herein as Condition 1. The Permittee shall not cause or allow the equipment to violate these standards/limits.

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

These conditions have been adopted into regulation as Standard Permit Condition IX (SPC IX). However, these conditions have been modified for this permit as follows:

- 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 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 also revised the Standard Permit Condition language for flares as incorporated into this permit in Condition 5 to read "*The Permittee shall observe one daylight flare event within 12 months after the preceding flare event observation or within 12 months after the permit effective date, whichever is later*." The Department has also revised the footnote to Condition 5 to read "*For purposes of this permit, a "flare event" is flaring of gas at a rate that exceeds the source's de minimis pilot, purge, and assist gas rates for a minimum of 18 consecutive minutes. It does not include non-scheduled release operations, i.e., process upsets, emergency flaring, or de minimis venting of gas incidental to normal operations*."

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 that 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, which 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 emissions standard for flares.

Gas-Fired Fuel Burning Equipment:

Monitoring – 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 visible emissions. Therefore, certification that an emission unit burns only natural gas ensures that the State visible emissions standard is met.

Reporting – 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 Equipment:

Monitoring – The visible emissions shall be observed using Method-9 as detailed in Condition 2. The Permittee has opted not to use the Smoke/No Smoke plan, so this option was not included in the permit. For EU IDs 19 through 21, the Permittee is required to do Visible Emissions Observations according to Conditions 2 through 4 if each unit operates more than the operating time limits in Condition 14. For EU IDs 28 through 33, the Permittee is required to do Visible Emissions Observations according to Conditions 2 through 4 if any individual unit operates more than 400 hours in any rolling 12-month period. Visible emissions shall be observed using the Method-9 Plan as detailed in Conditions 2 through 4. Corrective actions such as maintenance procedures and either more frequent or less frequent testing may be required depending on the results of the observations.

Recordkeeping – The Permittee is required to record the results of all visible emission observations.

Reporting - The Permittee is required to report: 1) the results of visible emissions observations, 2) incidents when emissions in excess of the State visible emissions standard or the BACT opacity limit have been observed, and 3) 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 22 and 23) requires annual Method 9 observations of scheduled flaring events lasting at least 18 consecutive minutes. The monitoring schedule for flares is within 12 months after the preceding flare event observation or within 12 months after the permit effective date, whichever is later. If an event does not occur within 12 months after the preceding event, then BPXA conducts a reading at the next scheduled event. In a practical sense, flaring events are intermittent, so the monitoring strategy in Condition 5 applies equally to both regularly- and intermittently-operated flares. The Permittee must report the results of these observations to the Department, however per Condition 5.3, no report is due if no event occurs during the reporting permit.

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

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

- EU IDs 1 through 23 and 28 through 33 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 nor industrial processes to violate this standard.

MR&R requirements are listed in Conditions 7 and 8 of the permit.

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

Gas-Fired Fuel Burning Equipment:

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 permit conditions meet the requirements of 40 C.F.R. 71.6(a)(3).

Monitoring – The monitoring of gas-fired emission units for particulate matter 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.

Reporting – 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 Equipment:

Monitoring – For EU IDs 19 through 21, as long as the emission units do not operate more than the operating time limits in Condition 14 (120 hours in any rolling 12-month period for each of EU IDs 19 through 21), monitoring shall consist of an annual compliance certification. For EU IDs 28 through 33, as long as any individual emission unit does not operate more than 400 hours in any rolling 12-month period, monitoring shall consist of an annual compliance certification.

If operating hours do not exceeds the IEU thresholds then for these units emissions are below the significant status threshold and 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 68 with the particulate matter standard.

Recordkeeping - The Permittee is required to record the results of PM source tests as set forth in Section 6.

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 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 and industrial processes in the State of Alaska.

- EU IDs 1 through 23 and 28 through 33 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.

Liquid Fuels:

For oil fired fuel burning equipment (EU IDs 19 through 21 and 28 through 33), the MR&R conditions are Standard Permit Conditions XI and XII adopted into regulation pursuant to AS 46.14.010(e).

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 meet the requirements of 40 C.F.R. 71.6(a)(3).

Gaseous Fuels:

Fuel gas sulfur is measured as hydrogen sulfide (H_2S) concentration in ppm by volume (ppmv). Fuel gas containing no more than 4000 ppmv H_2S will always comply with this emission standard. This is true for all fuel gases, even with no excess air. Fuel gas with an H_2S concentration of even 10 percent of 4000 ppmv is currently not available on the North Slope and is not projected to be available during the life of this permit.

For EU IDs 3 through 12, the Permittee shall comply with the SO_2 emissions standard in Condition 30 for NSPS Subpart GG and Condition 9.2. Other gas-fired equipment is subject to Condition 9.2.

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).

Condition 9.2 includes an option to reduce the frequency of periodic monitoring if a demonstration has been made that the fuel gas meets the definition of natural gas using the provisions allowed under NSPS Subpart GG, which are stated in Condition 30.1.b of the permit. Monitoring must still be conducted periodically in order to obtain the data needed to estimate actual SO_2 emissions for fees and to ensure gas properties do not change over time that is no longer meeting the NSPS Subpart GG natural gas definition.

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 copies of the records of the sulfur content analysis with the operating report.

Conditions 10 through 17, Pre-Construction Permit Requirements

Conditions 10 and 11, BACT 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/construction 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. EPA approved the latest SIP effective September 13, 2007.

Factual Basis: BACT Condition 10 applies because it was developed during PSD reviews of the stationary source by the EPA and the Department. BACT Condition 11 was added to this permit during this review as noted below. Conditions 10 and 11 require the Permittee to comply with the emission limits derived from BACT analysis. The Permittee may not cause or allow the affected equipment to violate these limits.

Between 1979 and 1981, EPA Region 10 issued four PSD permits for Prudhoe Bay stationary sources. On August 29, 1997 EPA issued revisions to the four PSD permits. The primary revisions include identification of specific equipment and tag numbers, apportionment of either field-wide or stationary source-wide ton per year limits to unit specific limits, and updating emission limits based solely on AP-42 factors to values in the edition of AP-42 that were current in 1997.

As part of the EPA process it was demonstrated to Region 10 that on a ton per year basis an overall decrease in allowable emissions would occur under the permit revision. The only exception was an increase in allowable SO_2 emissions due to subsequent permitting by the Department that raised the SO_2 BACT limit established by EPA in PSD IV for EU ID 7.

The majority of these changes (in Condition 10) reflect the revised emission limits granted by EPA on August 29, 1997. The EPA revision (PSD II) established ton per year emission limitations on a group basis for turbines. For EU ID 3 through 6, EPA established long term BACT emissions limits (tons per year) as well as short-term BACT emissions limits (*i.e.*, ppmv and lb/MMBtu) for NO_X, CO, and PM. For EU ID 7, EPA established long term BACT emissions limits (tons per year) and short-term BACT emissions limits (*i.e.*, ppmv and lb/MMBtu) for NO_X and CO, but only in terms of tons per year for PM. A BACT limit in terms of tons per year as well as annual average fuel gas H_2S concentration were also established for SO_2 emissions from EU ID 7. Short-term NO_X and CO BACT limits were carried forward to EU IDs 8 and 9 from the other exchanged turbine equipment permitted under EPA PSD II and PSD IV permits.

On December 12, 1989, ADEC established short-term BACT NO_X emission limits for EU IDs 10 through 12.

The U.S. EPA and ADEC BACT emissions limits and revisions have been incorporated into this Title V Operating Permit. For EU IDs 3 through 7, the Permittee is required to calculate and report emission levels for the NO_X, CO, and PM. In addition, for EU ID 7, the Permittee is required to calculate and report emission levels for SO_2. Monitoring for compliance with the short-term BACT emission limit for NO_X is identical to that for Subpart GG turbines.

On April 22, 2013, Minor Permit No. AQ0268MSS02 became effective. This permit did the following:

1) revised the existing fuel gas H_2S content BACT limit on EU ID 7 in Table 2 (referenced in Condition 6) of AQ0268TVP01 Rev. 1 from 30 ppmv annual average to 200 ppmv annual average and require monthly fuel gas H_2S analysis to demonstrate compliance;
2) revised the H_2S content of fuel gas burned in EU ID 7 in Condition 7 and Table 2 of AQ0268TVP01, Rev 1 from 30 ppmv annual average to 200 ppmv;

3) established a 'not-to-exceed' H_2S content limit of 140 ppmv or 200 ppmv for gas burned in EU IDs 1, 2, 5, 6, 8 through 18 depending on the sulfur content of the liquid fuel burned by other emission units;
4) established a 'not-to-exceed' H_2S content limit of 200 ppmv for gas burned in EU IDs 3, 4, 22, and 23;
5) established a liquid fuel sulfur content limit of 0.11 percent by weight (wt%) for existing liquid fuel-fired EU IDs 19, 20, and 21 at the FS#2 Production Pad; and
6) required monthly fuel sulfur analysis.

These requested limits and restrictions were incorporated into Conditions 8, 9, and 10 of Minor Permit No. AQ0268MSS02 and have been included in this permit (*i.e.*, AQ0268TVP02) under Conditions 10 and 11 and Table B.

Monitoring, Recordkeeping, and Reporting Requirements for Condition 10

Monitoring – For annual emission limits contained in Table B, the Permittee will use fuel consumption and/or hours of operation along with the emission factors contained in Section 15 to calculate monthly emissions and then use the monthly values to determine the 12-month period summation of emissions. The Department included requirements to conduct periodic source testing to verify Section 15 emission factors and visible emissions monitoring for units subject to the 10% opacity limit. Since turbine periodic testing is required for NSPS under Condition 29, the NO_X turbine test cross referenced Condition 30.

Recordkeeping – Maintain records of monthly BACT emission levels.

Reporting – Report compliance with annual emission limits for EU IDs 3 through 7. Notify the Department when annual emission limits are exceeded.

Monitoring, Recordkeeping, and Reporting Requirements for Condition 11

In accordance with AQ0268MSS02 Conditions 8 and 9, which revised Condition 7 of AQ0268TVP01 for EU ID 7 (BACT H_2S fuel gas concentration), and which have been incorporated under Condition 11 and Table B of this permit, the Permittee is required to monitor and record fuel gas H_2S concentration per Condition 11.4.a or liquid fuel sulfur content per Condition 11.4.b. Additionally, the Permittee is required to monitor and record monthly hours of operation in accordance with Condition 15. Also, the Permittee is required to comply with the reporting requirements in Condition 11.5.

Condition 12, PSD Applicability Requirements – MR&R for Annual SO_2 Emissions from Fuel Gas Combustion

Legal Basis: The projected actual emissions increase in SO_2 emissions from revisions made to the fuel gas H_2S concentration limits in Minor Permit No. AQ0268MSS02 (Condition 9), as incorporated in Conditions 10 and 11 and Table B of this permit, is 38.4 TPY; Therefore, the contemporaneous emissions increase resulting from fuel gas souring at the stationary source does not trigger PSD review. However, since the SO_2 emissions increase is greater than 50 percent of a significant emissions increase, BPXA must monitor and maintain a record of annual emissions for a period of 10 years as described in 40 C.F.R. 52.21(r)(6) and (7).

Minor Permit No. AQ0268MSS02 (Conditions 12, 13, and 14) contains requisite PSD applicability MR&R requirements carried forward to this Title V permit from AQ0268MSS02. These conditions are necessary because if future actual emissions exceed the baseline actual emissions by 40 TPY or more during the 10-year contemporaneous period after the permit is issued (*i.e.*, after "startup" of the project) then, PSD permitting would be triggered and a BACT analysis would have to be completed for sulfur dioxide emissions from all gas-fired and liquid-fired emission units at the source.

Factual Basis: Condition 12 was carried forward from Minor Permit No. AQ0268MSS02 (Conditions 12, 13, and 14). 40 C.F.R. 52.21(r)(6)(v)(c) requires MR&R to demonstrate that a future SO_2 actual emissions increase does not exceed the significant emissions increase threshold in 40 C.F.R. 52.21(b)(23)(i). As per Condition 12.3.b, the Permittee shall include information in the report to explain why the net change in emissions calculated under Condition 12.1.d for the preceding year reaches or exceeds 40 TPY.

Conditions 13 through 16, Permit-to-Operate Requirements Carried Forward

Legal Basis: The Permit-to-Operate No. 9473-AA011 contained owner-requested limits as conditions that must be carried forward to this Title V permit. These conditions contain requirements to measure fuel consumption so that emission levels may be calculated, and to monitor operating hours for emergency equipment and gas-fired turbines and heaters.

Factual Basis: The conditions listed here establish a PSD avoidance cap for post source modifications and caps to avoid ambient impact analysis of past projects. The permit decision record is unclear regarding the specific basis for each emission limit. Condition 13 requires the Permittee to limit the combined number of hours of operation per consecutive 12-month period for fuel gas-fired turbines, EU IDs 1 and 2.

Condition 14 requires the Permittee to limit the number of hours of operation per consecutive 12-month period for the EU IDs 19 through 21. The exceedance of the operational hour-limit is not a violation if the Department determines that the exceedance is due to an emergency.

Condition 15 requires the Permittee to monitor, record, and report the hours of operation for EU IDs 1 through 21 and 28 through 33.

Condition 16 requires the Permittee to monitor, record, and report the fuel consumption for EU IDs 1 through 23 and 28 through 33.

Condition 17, Owner Requested Limit

Legal Basis: Correspondence provided to BPXA from EPA dated August 11, 2005 specified EU IDs 24, 25, and 26 (tank tag nos. 16-1981, 16-1982 and 16-1983) are "process tanks" as defined under NSPS Subpart Kb at 40 C.F.R. 60.111b and "storage vessels" under 40 C.F.R. 60.111b (as amended October 15, 2003) do not include "process tanks" EPA concluded these tanks are not subject to NSPS Subpart Kb. However, the Permittee requests that the requirements of Subpart Kb be retained in the permit in order to establish an enforceable limit and, therefore, cap the potential emissions from these tanks.

Factual Basis: This condition has been included in the permit upon request from the Permittee.

Condition 18, Owner Requested Limit

Legal Basis: This condition has been included in Permit AQ0268TVP02 upon request from the Permittee.

Factual Basis: Although the provisions of 40 C.F.R. 63 Subpart ZZZZ allow affected emergency engines to operate up to 50 hours per calendar year for non-emergency situations other than maintenance and testing, the Permittee has requested to limit non-emergency operation of EU IDs 23 through 27 to maintenance and testing only, making the operating limit for these units more restrictive than the operations allowed under Subpart ZZZZ. Condition 18 outlines the requested restriction and associated monitoring, recordkeeping, and reporting.

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 non-road 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.

The Department finds that the insignificant units at this stationary source do not require specific monitoring, recordkeeping and reporting to ensure compliance under this condition.

Condition 19.4.a requires annual certification based on reasonable inquiry that the emission units did not exceed State emission standards during the previous year and did not emit any prohibited air pollution.

Conditions 20 through 27, NSPS Subpart A Requirements

Legal Basis: The Permittee must comply with the applicable New Source Performance Standard (NSPS) provisions incorporated by reference for specific industrial activities, as listed in 18 AAC 50.040[11].

Most affected facilities subject to an NSPS are subject to Subpart A. At this stationary source, EU ID 27 is subject to NSPS Subpart Ka, EU IDs 3, 4, and 8 through 12 are subject to the NO_X standards of NSPS Subpart GG, and EU IDs 3 through 12 are subject to NSPS Subpart GG for SO_2 and, therefore, subject to Subpart A.

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

Conditions 20.1 through 20.3 - The Permittee has already complied with the notification requirements in 40 C.F.R. 60.7(a)(1) and (3). However, the Permittee is subject to 40 C.F.R. 60.7(a)(1), (a)(3), and/or (a)(4) in the event of a new NSPS affected facility[12] or in the event of a modification or reconstruction of an existing facility[13] into an affected facility.

Condition 20.4 - The requirement to notify the EPA and the Department of any proposed replacement of components of an existing facility (40 C.F.R. 60.15) apply in the event that the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility.

Condition 21 - Start-up, shutdown, or malfunction record maintenance requirements in 40 C.F.R. 60.7(b) are applicable to all NSPS affected facilities subject to Subpart A.

Conditions 22 and 23 - NSPS excess emission reporting requirements and summary report form in 40 C.F.R. 60.7(c) & (d) are applicable to EU IDs 3 through 12. 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. The Permittee obtained EPA approval for annual instead of semi-annual fuel sulfur reporting in a letter from Jim McCormick (EPA Region 10) to Arco Alaska, Inc. dated Oct. 18, 1993. Therefore, the EEMSP reports that address fuel gas H_2S monitoring for Subpart GG-affected turbines are required to be submitted at least annually for these units instead of semi-annually.

Condition 24 - The Permittee has already complied with the initial performance test requirements in 40 C.F.R. 60.8 for EU IDs 3, 4, and 8 through 12. Therefore, the Permittee is not required to comply with 40 C.F.R. 60.8(b) through (e) for EU IDs 3, 4, and 8 through 12 and 27. 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 the EPA.

Condition 25 - Good air pollution control practices in 40 C.F.R. 60.11 are applicable to all NSPS affected facilities subject to Subpart A (EU IDs 3 through 12 and 27).

Condition 26 - States that any credible evidence may be used to demonstrate compliance or establishing violations of relevant NSPS standards for EU IDs 3 through 12, and 27. Although this condition imposes no currently applicable requirement or emission limit, it is included in the permit to ensure that the stationary source is not inadvertently shielded from this requirement and is aware of the requirement.

Condition 27 - Concealment of emissions prohibitions in 40 C.F. R. 60.12 are applicable to EU IDs 3 through 12, and 27.

The flares (EU IDs 22 and 23) are not subject to 40 C.F. R. 60.18 because they are safety devices and not control devices. The flares do not receive any tank vapors from any NSPS regulated emission units.

[12] *Affected facility* means, with reference to a stationary source, any apparatus to which a standard applies, as defined in 40 C.F.R. 60.2, effective 07/01/11.

[13] *Existing facility* means, with reference to a stationary source, any apparatus of the type for which a New Source Performance Standard (NSPS) is promulgated, and the construction or modification of which was commenced before the date of proposal of that standard; or any apparatus which could be altered in such a way as to be of that type, as defined in 40 C.F.R. 60.2, effective 07/01/11.

Recordkeeping requirements in 40 C.F.R. 60.7(f) are applicable to all NSPS affected facilities. (Satisfied by Condition 62).

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 28, NSPS Subpart Ka Requirements

Legal Basis: NSPS Subpart Ka applies to storage vessels for petroleum liquids with storage capacity > 40,000 gallons that were built or modified after May 18, 1978 and prior to July 23, 1984. EU ID 27 was constructed during this time frame. This affected facility has a storage capacity of greater than 40,000 gallons and stores petroleum liquids.

Factual Basis: Condition 28 requires the Permittee to operate and maintain EU ID 27 and the closed vent vapor recovery system (installed according to the specifications of 40 C.F.R. 60.112a(a)(3)) in accordance with the Operations and Maintenance Plan on file with the EPA. As the Department does not have a copy of this plan, the condition requires a one-time submittal of this plan with the first quarterly permit operating report.

Conditions 29 through 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, 59ºF, 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. EU IDs 3 through 12 are subject to NSPS Subpart GG. EU IDs 5 through 7 are exempt from the NSPS Subpart GG NO_X standard (see below).

Factual Basis: These conditions incorporate NSPS Subpart GG NO_X emission and sulfur compound limits. The Permittee may not allow equipment to violate these standards. Per Condition 30.1.b and pursuant to 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. Per Condition 30.1.c, 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. The Permittee was granted an EPA-approved Custom Fuel Monitoring Schedule (7/13/93 with additional correspondence on 8/20/93, 10/18/93, and 8/19/96) and Alternate H_2S Sampling Method (10/2/97) allowing the Permittee to determine the sulfur content of the fuel gas at least monthly using ASTM D 4810-88, ASTM D 4913-89, Gas Producer's Association (GPA) Method 2377-86. The custom schedule also allows the Permittee to reduce the required frequency for reporting the fuel sulfur content to once per year, instead of the standard semi-annual requirement. Per 40 C.F.R. 60.334(i)(3)(i), a custom sulfur monitoring schedule under 60.334(i)(3)(ii)(A) is acceptable without prior Administrative approval.

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

$$STD_{NO_x} = 0.015\left(\frac{14.4}{Y}\right) + F$$

Where:

STD_{NO_x} = allowable NO_X 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 stationary source. The value of Y shall not exceed 14.4 kJ/W-hr; and

F = NO_X emissions allowance for fuel bound nitrogen, percent by volume, assumed to be zero for distillate fuel oil and North Slope gaseous fuels.

Based on the manufacturer's heat rating at manufacturer's rated peak load, and assuming fuel bound nitrogen of zero, the NO_X standard is 173 ppmvd for EU IDs 3 and 4, 164 ppmvd for EU IDs 8 and 9, and 176 ppmvd for EU IDs 10 through 12. Although the NO_X standard for EU IDs 10 through 12 is 176 ppmvd under Condition 29.3, the Permittee is required to comply with a 1989 ADEC NO_X BACT limit (Permit No. 9473-AA011) of 125 ppmvd under Condition 10.

EU IDs 5 through 7 are exempt from 40 C.F.R. 60.332 Subpart GG NO_X requirements because they satisfy the exemptions listed in 40 C.F.R. 60.332(e).

SO_2 Standard: The Permittee is required to comply with the following sulfur requirements for EU IDs 3 through 12 (turbines): [14]

(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 3 through 12 to exceed 0.8 percent by weight.

The Permittee has elected to comply with the SO_2 standard by not exceeding the 0.8 percent by weight sulfur content in the fuel burned by the affected emission units.

Exemptions: Gas turbines exempted from NSPS Subpart GG emission standards are as provided in 40 C.F.R. 60.332(e) – (l).

Conditions 29.4 through 29.6, NO_X Monitoring, Recordkeeping, and Reporting

Legal Basis: Periodic monitoring, recordkeeping, and reporting (MR&R) are included in Conditions 29.4 through 29.6 for *all* turbines that normally operate for greater than 400 hours in a 12 month period, including turbines not subject to NSPS Subpart GG emission standards. This additional monitoring is necessary to ensure that turbine emissions comply with the applicable BACT, ORL, and NSPS NO_X standards 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.

[14] The Permittee is also required to comply with the SO_2 BACT limits under Conditions 10 and 11.

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 BACT, ORL, or Subpart GG NO_X emission limit will inherently comply with the BACT, ORL, and Subpart GG limit at all times and will never need additional testing. After a sufficient body of NO_X data is gathered under monitoring conditions for compliance with BACT, ORL, and 40 C.F.R. 60, Subpart GG limits, the Department may find that it has enough information to make such categorical determinations. In that event, the Department would revise the NO_X monitoring conditions. The Department may determine that to assure compliance it is necessary to retain or increase the current monitoring frequency.

Fuel-bound nitrogen monitoring is clarified in the latest version of NSPS Subpart GG to be required only when the fuel-bound nitrogen content has been used as a basis for relaxing the NO_X emission standard of the subpart per 40 C.F.R. 60.332(a)(3) & (4) and §60.334(h)(2). Therefore, fuel-bound nitrogen monitoring is not required even without an EPA waiver.

These conditions do not include the initial NSPS performance test requirements as the Subpart A conditions cover these requirements. An existing or new turbine under this permit that 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 NO_X emissions at less than or equal to 90 percent of each of the limits shown in Conditions 10 and/or 29, then periodic monitoring is required within a year of the effective date of the permit if a turbine normally operates more than 400 hours within a 12 month period, or within a year of exceeding 400 hours of operation within a 12-month period (testing trigger event) 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 29.5.a(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 any of the emissions listed in Conditions 10 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[15]" 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 29.4.b(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 NO_X 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.

Conditions 30.1 through 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, recordkeeping, 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.

[15] *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 facility has been rendered inoperable by an emergency situation, as defined in 40 C.F.R. 60.331(e), effective 10/8/09.

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 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 July 13, 1993, August 20, 1993, October 18, 1993, August 19, 1996, and October 2, 1997. The approved alternative plans and schedules apply to EU IDs 3 through 12 since they commenced construction, reconstruction, or modification after October 3, 1977, but before July 8, 2004, per 40 C.F.R. 60.334(h)(4).

Per Conditions 30.1.b and 30.4.a(ii) 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 the gaseous fuel combusted by affected emission units 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 and reporting.

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 62.

Reporting: NSPS Subpart GG fuel sulfur standard reporting requirements are incorporated in the permit in Condition 30.4. Flow Station #2 has an annual schedule for reporting fuel sulfur as per a custom fuel monitoring schedule (EPA Letter: 10/18/93).

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 22 and 23, the Permittee is required to report as excess emissions any periods during which the sulfur content of the fuel being fired in the turbine exceeds 0.8 percent.

As of 7/1/11 (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 the stationary source reduced the required frequency of these reports to at least annually. As stated in Conditions 22 and 23, reports are to be submitted to the Department and EPA, and summarized in the operating report required under Condition 67. However, per Conditions 30.1.b and 30.4.a(iii), 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.

In Condition 30.4.b, the Department requires that a copy of the results from the monitoring requirements in Condition 30.1 be included in the operating report required under Condition 67. State excess emissions and permit deviation reports are to be submitted in accordance with Condition 30.4.c.

Condition 32, NESHAP Subpart A Requirements

Legal Basis: The Department has incorporated by reference the NESHAP requirements effective July 30, 2010, for specific industrial activities, as listed in 18 AAC 50.040(c).

Most affected facilities subject to a NESHAP requirement are subject to Subpart A. The Permittee shall comply with the applicable requirements of 40 C.F.R 63 Subpart A as specified in the provisions for applicability of Subpart A in 40 C.F.R. 63, Subpart ZZZZ Table 8.

Factual Basis: This condition incorporates applicable 40 C.F.R. 63 requirements. The Permittee may not cause or allow violations of these requirements.

Conditions 31 and 33 through 35, NESHAP Subpart ZZZZ Requirements

Legal Basis: The provisions of 40 C.F.R. 63, Subpart ZZZZ apply to owners or operators of a stationary Reciprocating Internal Combustion Engine (RICE) at a major or area source of HAP emissions, except if the stationary RICE is 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 19 through 21 and 28 through 33) whose construction commenced before June 12, 2006.

Factual Basis: Pursuant to 40 C.F.R. 63.6585, diesel-fired emergency generator EU IDs 19, 20, 28 through 33 and diesel-fired non-emergency fire water pump EU ID 21[16] are affected stationary RICEs subject to NESHAP Subpart ZZZZ. EU IDs 19, 20, and 28 through 33 are emergency RICE with a rating greater than 500 Hp and EU ID 21 is a non-emergency RICE with a rating less than 300 Hp and therefore these engines are not subject to any numerical emission limitations under Subpart ZZZZ.

For EU IDs 19 through 21 and 28 through 33, the Permittee must comply with 40 C.F.R. 63, Subpart ZZZZ no later than May 3, 2013.

Per 40 C.F.R. 63.6645(a)(5), initial notification is not required for existing stationary emergency CI RICEs or existing stationary CI RICEs that are not subject to any numerical emission standards.

In accordance with 40 C.F.R. 63.6603, EU IDs 19 through 21 and 28 through 33, must comply with the management practices in Table 2d of 40 C.F.R. 63 for emergency or non-emergency ($\leq$ 300 Hp) CI engines, as applicable.

The Permittee must comply with the good air control practices of 40 C.F.R. 63.6625(e).

The Permittee must use only ULSD liquid fuels in EU ID 21.

The Permittee must comply with the operational limitations for emergency generators for EU IDs 19, 20, and 28 through 33 under 40 C.F.R. 63.6640(f). (Note: EU IDs 28 through 33 are also subject to more restrictive operating limits than those required by Subpart ZZZZ as requested by the Permittee and included in this permit as Condition 18.)

[16] EU ID 21 has been classified as non-emergency RICE for purposes of Subpart ZZZZ applicability determination per BPXA letter of August 2, 2012.

For EU IDs 19, 20, and 28 through 33, the Permittee must comply with the installation and maintenance requirements of 40 C.F.R. 63.6625(e) and (f), including the requirement to install a non-resettable hour meter, if one is not already installed. For EU ID 21, the Permittee must comply with the maintenance requirements of 40 C.F.R. 63.6625(e).

For EU IDs 19, 20, and 28 through 33, the Permittee must comply with the recordkeeping requirements of 40 C.F.R. 63.6655(e) and (f) and 40 C.F.R. 63.6660. For EU ID 21, the Permittee must comply with the recordkeeping requirements of 40 C.F.R. 63.6655(e) and 40 C.F.R. 63.6660.

The Permittee must report any deviations from the General Monitoring, Operation, and Maintenance Requirements in Condition 33.

Condition 36, 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 37, Protection of Stratospheric Ozone, 40 C.F.R. 82

Legal Basis: Condition 37.1 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 that will apply if the Permittee uses certain refrigerants and engages in the recycling or disposal of certain refrigerants.

Conditions 37.2 and 37.3 prohibitions also 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 Flow Station #2 uses halon and is therefore subject to the Federal regulations contained in 40 C.F.R. 82.

Factual Basis: The regulations found in 40 C.F.R. 82 Subpart F regarding refrigerant recycling and disposal include adequate monitoring and reporting requirements The Permittee is not currently engaged in such activity, so simply citing the regulatory requirements is sufficient to ensure compliance with this Federal regulation. This condition also incorporates the applicable halon prohibitions from 40 C.F.R. 82, Subparts G and H. The Permittee may not cause or allow violations of these prohibitions.

Condition 38, NESHAPs Applicability Determinations

Legal Basis: This condition requires the Permittee to determine rule applicability of NESHAPS, and requires record keeping for those determinations if required by the source classification.

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. This condition requires the Permittee to notify the Department and Administrator if the stationary source becomes an affected facility and to keep and make available to the Department copies of the major stationary source determination.

Conditions 39 through 41, 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 operating permit program of November 30, 2001, as updated effective November 9, 2008.

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

Condition 42, 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 43 through 44, 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 Permit 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. The Department made changes to the standard permit language because this is one of three operating permits covering air activities at FS#2. The Department concluded that the standard permit conditions as modified meet the requirements of AS 46.14.250.

These 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 shall be paid on any pollutant emitted whether or not the permit contains any limitation of that pollutant.

These standard conditions specify that, unless otherwise approved by the Department, calculations of assessable emissions 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 45, 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 3 through 12 and 19 through 21, 27, and 28 through 33.

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). Records kept in accordance with Condition 45.2 for units previously subject to GAPCP need to be maintained for 5 years in accordance with Condition 62 even if a unit is no longer subject to this condition.

The Department determined that this standard permit 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 permit 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 46, 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 47, 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 engaging 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 may 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 enhanced monitoring or recordkeeping.

Condition 48, 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 a stack or stationary 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 unit or stack would need to be modified to accommodate stack injection.

Condition 49, 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 emission 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 permit 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.

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 a summary of the investigation and corrective actions undertaken for these complaints. The Permittee is also required to submit copies of these records upon request of the Department.

Condition 50, 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 66. Excess emission reporting under Condition 66 requires information on the steps taken to minimize emissions. Monitoring of compliance for this condition consists of the report required under Condition 66.

Condition 51, 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. Condition 51.1 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 68.

Condition 52, 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 its operating permit program approved by EPA 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 53 through 55, 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 this permit to conduct source tests. The Permittee is required to conduct source tests in the manner set out in Conditions 53 through 55.

Factual Basis: These conditions supplement the specific monitoring requirements stated elsewhere in this permit. Compliance monitoring with Conditions 53 through 55 consists of the test reports required by Condition 60.

Condition 56, 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), 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 57 through 60, 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 by this permit to conduct source tests.

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 61, Particulate Matter (PM) 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 PM standards in 18 AAC 50.055.

Factual Basis: This condition supplements specific monitoring requirements stated elsewhere in this permit.

Condition 62, 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 63, 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 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, although excess emission reports must be submitted more frequently than the operating report. This condition supplements the reporting requirements of this permit.

Condition 64, 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 lists the Department's appropriate address for reports and written notices. 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 standard reporting and notification requirements of this permit.

Condition 65, 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) under the Federally-approved State operating permit program effective November 30, 2001, as updated effective November 9, 2008.

Factual Basis: This condition requires the Permittee to submit information requested by the Department. Monitoring consists of receipt of the requested information.

Condition 66, 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 Permit Condition III under 18 AAC 50.346(c) pursuant to AS 46.14.010(e). 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 that unit-specific or stationary-source-specific conditions would better meet the requirements. Therefore, the Department concludes that the standard permit condition meets the requirements of 40 C.F.R. 71.6(a)(3).

Section 13, Notification Form

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

There have been some historical misunderstandings regarding permit deviations and excess emissions. Not all permit deviations are excess emissions, but all excess emissions of limits set out in the permit are also permit deviations. Example permit deviations that are not also defined as excess emissions include, but are not limited to, a failure to report required information, incorrect or incomplete reported information, submittal of a report after the required deadline, failure to conduct monitoring prior to the required deadline, failure to maintain required records, etc.

Condition 67, 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). By submitting a quarterly operating report on the 45th day after the close of the quarter's end, compliance records come in roughly 3 months earlier for half the period of operation and 15 days later for the other half. Overall this benefits the Department.

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 reporting 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 68, 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. Each annual certification provides monitoring records for compliance with this condition.

Condition 68.2 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 was 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.

The Permittee is required to submit to the Department an original and one copy of an annual compliance certification report. The Permittee may submit one of the required copies electronically at their discretion. Electronic submission meets the requirements of 18 AAC 50 and allows for more efficient distribution of the certification report to staff in other locations.

Condition 69, NSPS and NESHAP Reports

Legal Basis: The Permittee is required to provide the Federal Administrator and Department with a copy of each emission unit report 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.

Condition 70, 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 follows shortly after sources report actual emissions for assessable emissions purposes and provides the Department sufficient time to enter the data into EPA's electronic reporting system. It is noted that the Permittee has requested this date be changed to April 30 due to multiple other reporting requirements for this stationary source. This request notwithstanding, the Department has not revised the reporting date, as it is published in the Standard Permit Condition XV and ADEC has not been granting extensions as the extension does not meet ADEC's timing need to process the reported information.

The air emissions reporting requirements under 40 C.F.R. Part 51 Subpart A apply to States. However, States rely on stationary source information to meet the State's reporting requirements of Part 51 Subpart A. FS#2 is classified as a "Type A" source for inventory purposes.

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 a Type A source only needs to submit a single type of report every year instead of both an annual report and a separate triennial report every third year. The Department asserts that this more effectively meets the regulatory need. Other than streamlining the non-applicable standard permit condition text to remove obligations that are not applicable, no other text of the standard permit condition has been changed.

Condition 71, Permit Applications and Submittals

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

Factual Basis: Standard Permit 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 72 through 74, 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 conditions are 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 72.

Condition 75, 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 accordance 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 76 through 79, General Compliance Requirements and Schedule

Legal Basis: These conditions ensure compliance with the applicable requirement in 18 AAC 50.326(j)(3) and 40 C.F.R. 71.6(c). The Permittee is required to comply with these standard permit conditions set out in 18 AAC 50.345 and 40 C.F.R. 71.6(c) 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 general compliance conditions are required for all operating permits.

Conditions 81 through 82, Permit Shield

Legal Basis: These conditions ensure compliance with the applicable requirements 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 under these conditions under the Federally approved State operating permit program effective November 30, 2001, as updated effective November 9, 2008.

Factual Basis: Table C of Operating Permit No. AQ0268TVP02 shows the permit shields that the Department granted to the Permittee. The Department based the determinations on the permit application, past operating permit, Title I permits and inspection reports. Should any of the shielded requirements become applicable during the permit term, the Permittee is required to take necessary steps to comply with all applicable requirements in a timely manner.

Table R describes permit application shield requests that have been denied, and the Department's rationale for the decision.

Table R - Permit Shields Denied

Permit Shield Requested	Reason for Shield Request	Reason for Shield Denial
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.	There is no rationale to shield the Permittee from a requirement that the Department may request at any time.

ATTACHMENT A

FIGURE 1--SUMMARY REPORT--GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

[Note: This form is referenced in 40 C.F.R. 60.7, Subpart A-General Provisions]

Pollutant *(Circle One)*: SO_2 NO_X TRS H_2S CO Opacity

Reporting period dates: From ________________________ to ____________________________

Company:
Emission Limitation: ____

Address: ____

Monitor Manufacturer: ____

Model No.: ____

Date of Latest CMS Certification or Audit: _____________________________

Process Unit(s) Description: ____

Total emission unit operating time in reporting period [1]: ____________________________

Emission Data Summary [1]	**CMS Performance Summary** [1]
1. Duration of excess emissions in reporting period due to:	1. CMS 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 emissions .... ____	2. Total CMS Downtime .... ____
3. Total duration of excess emissions x (100) / [Total EU operating time] .... ____ % [2]	3. [Total CMS Downtime] x (100) / [Total EU 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 downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 C.F.R. 60.7(c) shall be submitted.

<u>Note</u>: *On a separate page, describe any changes since last quarter in CMS, process or controls.*

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

Name: ____

Signature: ____ *Date*: ___________________

Title: ____