Alaska Department of Environmental Conservation
Air Permits Program

BP Exploration (Alaska) Inc. (BPXA)
Seawater Injection Plant East (SIPE)

STATEMENT OF BASIS
of the terms and conditions for
Permit No. AQ0170TVP02

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INTRODUCTION

This document sets forth the statement of basis for the terms and conditions of Operating Permit No. AQ0170TVP02.

SEAWATER INJECTION PLANT EAST STATIONARY SOURCE IDENTIFICATION

Decision

Seawater Injection Plant East is located within the Prudhoe Bay Unit (PBU) on the North Slope of Alaska. The Department has determined the Seawater Injection Plant East (SIPE) stationary source is the surface structures with their associated emission units located on the SIPE pad. This determination applies to both the State's Title I and Title V air quality permitting programs.

Currently, the significant emission units on that pad for Title V purposes are those identified in Table A of Operating Permit No. AQ0170TVP02. Additional insignificant emission units are located on the SIPE pad.

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.
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> *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, BPXA is the operator and implements the decisions of the leaseholders via the Unit Operating Agreement.

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

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

The PBU production centers and production wells are located on separate pads that are not contiguous (i.e., not touching). Thus the adjacency (i.e., the nearness or closeness) must be evaluated. To evaluate the adjacency of facilities, ADEC has used the concept of the common sense notion of a plant to inform proximity. In its analysis, ADEC has developed what is referred to as the "wagon wheel" model based on the production centers (hubs) and well pads (spokes). In this model of the plant, the well pads deliver raw materials (wellhead fluids consisting of crude oil, water, and hydrocarbon gases) to the production center for processing into finished product (sales oil) for delivery and custody transfer at Pump Station #1 of the Alyeska Pipeline Service 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 ADEC does not propose to establish a fixed value for this parameter. For instance, the longest spoke at Lisburne is drill site DS-L5, which is 6 miles from the production center (hub), at Endicott is drill site SDI, which is 3 miles from the production center (hub), at Kuparuk is drill site 3R, which is 3 miles from the CPF-3 production center (hub), and at Alpine is drill site DS2, which is 3 miles from the production center (hub). Within the 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 are, of course, determined by the flow of wellhead fluids (raw materials) and sales oil (finished crude). Whether a production well pad is part of a larger stationary source centered at a production center (hub) will be determined on a case-by-case basis taking into consideration site-specific factors such as the common sense notion of a plant, air impact overlaps/airshed, predictable emission impacts on hub, different operating units/control, service contracts with other operating units, ease of permit administration, and other case-specific factors deemed relevant. For instance, for a new unitized development the presumptive maximum radius of the spokes would be based on the original development project. Under the wagon wheel model, the associated infrastructure is considered a separate stationary source, unless co-located on the same pad or primarily associated with a hub or another stationary source.

Rationale for Hub and Spoke Aggregation Model

In the context of the 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 well pads (spokes) as the basic stationary source or production plant for the PBU?

1) *Proximity.* The primary function of the production centers at the PBU (GC-1, GC-2, GC-3, FS-1, FS-2, FS-3, and Lisburne) is separation and processing of three-phase well fluids (oil, gas, and water) into sales-quality crude oil for delivery to the Trans-Alaska Pipeline System at Pump Station #1. Each production center is capable of performing this function independently of the other production centers. For example, if FS-2 were 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 well pads with their respective production centers maintains the important role of proximity in aggregation decisions.

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

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

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

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

3) *Reasonable Permit Administration.* This approach allows ADEC more feasible permit administration with comparable environmental benefits. The benefit of going beyond the reasonably scaled wagon wheel approach for evaluating emission effects on other facilities is not apparent. Finally, previous permitting actions by ADEC at Kuparuk,

Lisburne, Endicott, and Alpine support the determined stationary sources using the hub and spoke model. The facilities within the PBU would then be treated the same as these other operating units.

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 ADEC does not believe that the leases and operating units constructed from these leases is the proper focus of a regulatory program concerned with air emissions. The leases and unit agreement pertain to subsurface development and long-term reservoir management to maximize economic gain for the leaseholders and lessor. If the Prudhoe Bay operating unit were to be determined the relevant 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 ADEC does not believe this is a deciding factor because in the oil and gas industry pipelines connect everything. Pipelines are used throughout the operating unit as the preferred method for transferring fluids between facilities. To only consider the connectivity of operations via pipelines to determine proximity and to not also consider the concept of a common sense notion of a plant would result in one stationary source extending from the North Slope oil fields all the way to the Valdez Marine Terminal.

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

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

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

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

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

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

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

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

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

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

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

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

<u>Status of Support Facilities at PBU</u>

The services that support facilities provide (e.g., Seawater Treatment Plant, Grind & Inject, Base Operations Center, Central Power Station, Seawater Injection Plant East, 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 Seawater Injection Plant East and Flow Station #1 are in close proximity to each other (approximately ½ mile) but don't meet the criterion of common sense notion of a plant so are not aggregated. The function of Seawater Injection Plant East is to inject water into the producing formation for enhanced oil recovery thereby benefiting all PBU production centers whereas the function of Flow Station #1 is to produce crude oil for sales.

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

1) Physical proximity - the two facilities are located ¼ of a mile from each other.

2) Common sense notion of a plant - these two facilities constitute the gas handling plant. The raw material (low pressure high molecular weight gas) is delivered to CGF from the hubs for removal of miscible inject/natural gas liquids and pressurization (to intermediate pressure) for distribution, the vast majority of which is delivered to the Central Compressor Plant for additional pressurization. This final product (high pressure low molecular weight gas) is then distributed to injection wells nearby CCP for ultimate disposal/storage underground.

3) These two facilities were originally permitted as a single stationary source but were disaggregated during the late 1980s.

Satellite Field Development

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

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

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

1) Production well pads and their emission units that lie within the original development project surface area are presumed to be part of the existing hub stationary source to which they deliver well fluids unless compelling reasons justify their exclusion.

2) Production well pads and their emission units that lie outside the original development project surface area are presumed NOT to be part of the existing hub stationary source to which they deliver well fluids unless compelling reasons justify their inclusion.

3) For existing stationary sources, such as Alpine, Endicott, Northstar, and Badami that do not have an established original development project surface area because they consist of only one or two production well pads, other factors will need to be considered when determining whether the well pad and its emission unit should become part of the existing stationary source.

STATIONARY SOURCE IDENTIFICATION

Section 1 of Operating Permit No. AQ0170TVP02 contains information on the stationary source as provided in the Title V permit application.

The stationary source is owned and operated by, BP Exploration (Alaska) Inc. and BP Exploration (Alaska) Inc. (BPXA) is the Permittee for the stationary source's operating permit. The SIC code for this stationary source is 1311 - Water Flood in Support of Crude Petroleum and Natural Gas and the NAICS Code is 211111 - Crude Petroleum and Natural Gas Extraction .

The Seawater Injection Plant East (SIPE) receives low pressure treated seawater from the Seawater Treatment Plant (STP), heats and increases the pressure of the seawater, and then distributes the water to the various drill sites for injection into the various reservoirs.

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 Seawater Injection Plant East (SIPE) that are classified and have specific monitoring, recordkeeping, and reporting requirements are listed in Table A of Operating Permit No. AQ0170TVP02.

Table A of Operating Permit No. AQ0170TVP02 contains information on the emission units regulated by this permit as provided in the permit 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 to the stationary source.

EMISSIONS

A summary of the potential to emit (PTE)[1] and assessable PTE as indicated in the application from the Seawater Injection Plant East (SIPE) is shown in the table below.

Table F - Emissions Summary, in Tons Per Year (TPY)

Pollutant	NOx	CO	PM-10	SO_2	VOC	HAPs	Total
PTE	2,189	497	26	155	12	8.82	2,879
Assessable PTE	2,189	497	26	155	12	0	2,879

The assessable PTE listed under Condition 31.1 is the sum of the emissions of each individual regulated air pollutant for which the stationary source has the potential to emit quantities greater than 10 TPY. The emissions listed in Table A are estimates that are for informational use only. The listing of the emissions does not create an enforceable limit to the stationary source.

[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.

For criteria pollutants, emissions are as provided in the Title V permit renewal application dated June 26, 2008. All NOx and CO emissions for turbines and heaters are based on the limits set by EPA PSD-X81-01, as amended August 29, 1997. The PTE for all other criteria pollutants and emission unit combinations were_based on AP-42 emission factors current as of the date of the permit renewal application submittal, source test results, vendor supplied emission factors, and/or operational limits applicable to emission units at the stationary source. Potential emissions from the emergency IC engines were estimated based on 500 hours of operation per year per unit, consistent with the EPA's J. Seitz memo for an emergency unit dated September 6, 1995. The existing equipment at the stationary source does not have SO_2 BACT limits.

For this renewal permit, BPXA used a higher assumed fuel gas H_2S gas content of 245 ppmv (30 ppmv in the initial Title V Permit No. AQ170TVP01) and liquid fuel sulfur content of 0.11 percent by weight (0.5 percent by weight in the initial Title V Permit No. AQ170TVP01) to calculate SO_2 PTE using mass balance equation. The Department is not making a Title I permit applicability determination regarding anticipated fuel gas souring as part of this renewal permit decision.

As provided in the Title V permit renewal application, HAP emissions from combustion units were calculated using field data from GRI-HAPCalc version 3.01 software, AP-42 emission factors, and Ventura County Air Pollution Control District (VCAPCD) emission factors. HAP emissions from tanks were estimated using TANKS v4.09d. Turbine and heater emissions were estimated using the EPA/ GRI Field/ GRI Literature emission factor set, which provides very conservative results. Emissions from the Broach heaters were estimated based on classification of these units as boilers. The GRI "boiler" emission factors are appropriate for hot water heaters (where the heated water is at <160 psig and <210 deg. F) and for steam generating units. Liquid fuel-fired IC engine HAP emissions were estimated using AP-42 emission factors with engine operations set at 500 hours per year. _HAP estimates were not included in the total in the table above because most HAPs are VOCs. The stationary source is not a major source of HAPs. The highest individual HAP is less than 10 TPY and cumulative HAPs are less than 25 TPY from the stationary source.

BASIS FOR REQUIRING AN OPERATING PERMIT

In accordance with AS 46.14.130(b), an owner or operator of a Title V source[2] 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;
- 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 under Section 112 of the Clean Air Act;
- 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) and 40 C.F.R. 71.3(a) as

[2] *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 major stationary source 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;
- A source, including an area source, subject to a standard, limitation or other requirement under Section 111 of the Act (Standards of Performance for New Stationary Source, NSPS) not exempted or deferred under AS 46.14.120(e) or (f);

AIR QUALITY PERMITS

Previous Air Quality Permit to Operate/EPA PSD Permit

Permit to Operate No. 9473-AA013 was issued on November 30, 1994. This permit-to-operate included all construction authorizations issued through November 30, 1994, (as well as a "unilateral" amendment dated July 29, 1996, which was made to all State Operating Permits). The permit to operate was issued before January 18, 1997 (the effective date of the new divided Title I/Title V permitting program). The permit to operate incorporated terms and conditions of EPA Prevention of Significant Deterioration (PSD) Permit No. PSD-X81-01. The PSD permit contained specific BACT requirements for the stationary source. On August 29, 1997, the EPA revised Permit No. PSD-X81-01 and established NOx and CO ton per year emission limitations that apply to individual turbines and heaters. In addition, EPA established short-term NOx and CO BACT emission limits in terms of ppmv or lb/MMBtu. Visible emission limits were established by EPA in terms of percent opacity. The permit to operate revision to include the August 29, 1997 PSD permit revision is explained below. All effective stationary source-specific requirements established in these permits are included in the renewal operating permit as described in Table I.

Title I (Construction) Permits

On November 19, 1997, ARCO Alaska, Inc. (ARCO) submitted a construction permit application requesting revisions to Permit to Operate No. 9473-AA013 along with the Title V operating permit application for the SIPE. 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 the stationary source. BPXA will be identified as the applicant for the remainder of this document. In the construction permit application, BPXA proposed that terms and conditions in the permit to operate be updated and made identical with the specific revisions of EPA PSD Permit No. PSD-X81-01 (PSD III), amended August 29, 1997. 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 updating emission limits based solely on AP-42 factors to the values in the edition of AP-42 that was current in 1997.

The majority of the changes reflect the revised emission limits granted by EPA on August 29, 1997. Table G and Table H below identify and explain the source inventory corrections and emission limits revisions made to Permit to Operate No. 9473-AA013. These revisions were done under Operating/Construction Permit No. AQ0170TVP01 issued on October 27, 2003 and revised on February 17, 2004. These updates are now carried forward to this renewal Title V Operating Permit No. AQ0170TVP02, as shown in Table I below.

Table G – Operating/Construction Permit No. AQ0170TVP01 Source Inventory Revisions

Equipment Tag No..	Permit to Operate No. 9473-AA013 Rating	Operating/Construction Permit No. AQ0170TVP01 New Revised Rating	Explanation
Gas-Fired Turbines			
NGT-31-15101 NGT-31-15102 NGT-31-15301 NGT-31-15302 NGT-31-15303 NGT-31-15304	29,070 Hp ISO 29,070 Hp ISO 2,500 Hp ISO 2,500 Hp ISO 2,500 Hp ISO 2,500 Hp ISO	29,070 Hp ISO or 33,300 Hp ISO 29,070 Hp ISO or 33,300 Hp ISO No Change No Change No Change No Change	RB211-24A or RB211-24C units could be in use at the stationary source. The ratings are provided for both turbine models.
Gas-Fired Heaters			
NGH-31-14101 NGH-31-14102	200 MMBtu/hr 200 MMBtu/hr	Removed from permit	These units are blinded off and out of service
NGH-31-1401 NGH-31-1402	67.2 MMBtu/hr 67.2 MMBtu/hr	No Change	
Diesel-Fired Equipment			
EDG-31-2813 EDG-31-1501	3,600 Hp 195 Hp	No Change	

Table H – Operating/Construction Permit No. AQ0170TVP01 Emission Limits Revisions

Pollutant	Equipment Tag No.	Permit to Operate No. 9473-AA013 Limit	Operating/ Construction Permit No. AQ0170TVP01 Revised Limits[3] for Each Unit	Explanation
NOx	**Turbines** NGT-31-15101 NGT-31-15102	150(14.4/Y) ppmvd @ 15% O_2 and 751 TPY (each)	150(14.4/Y) ppmvd@ 15% O_2 (208 ppmvd @ 15% O_2) and 885 TPY	EPA PSD III BACT and 8/29/97 permit revision.
	Turbines NGT-31-15301 NGT-31-15302 NGT-31-15303 NGT-31-15304	150(14.4/Y) ppmvd @ 15% O_2 and 65 TPY (each)	150(14.4/Y) ppmvd @ 15% O_2 (150 ppmvd @ 15% O_2) and 86 TPY	
	Heaters NGH-31-1401 NGH-31-1402	0.08 lb/MMBtu	0.08 lb/MMBtu and 26 TPY	EPA PSD III BACT and 8/29/97 permit revision.
	Diesel-fired Units EDG-31-2813 EDG-31-1501	No limit	No limit	No BACT or other limits apply.
CO	**Turbines** NGT-31-15101 NGT-31-15102	109 lb/MMscf fuel gas	0.17 lb/MMBtu and 178 TPY	EPA PSD III BACT and 8/29/97 permit revision.
	Turbines NGT-31-15301 NGT-31-15302 NGT-31-15303 NGT-31-15304	109 lb/MMscf fuel gas	0.17 lb/MMBtu and 24 TPY	EPA PSD III BACT and 8/29/97 permit revision.

3 These limits do not include applicable Alaska SIP limits, unless otherwise specified.

Pollutant	Equipment Tag No.	Permit to Operate No. 9473-AA013 Limit	Operating/ Construction Permit No. AQ0170TVP01 Revised Limits[3] for Each Unit	Explanation
	Heaters NGH-31-1401 NGH-31-1402	0.018 lb/MMscf	0.061 lb/MMBtu and 20 TPY	EPA PSD III BACT and 8/29/97 permit revision.
	Diesel-fired Units EDG-31-2813 EDG-31-1501	No limit	No limit	No BACT or other limits apply.
Opacity	**Turbines** NGT-31-15101 NGT-31-15102 NGT-31-15301 NGT-31-15302 NGT-31-15303 NGT-31-15304	10%, 3 minutes/hr	10%, consecutive 6-minute average	EPA PSD III BACT and 8/29/97 permit revision.
	Heaters NGH-31-1401 NGH-31-1402	5%, 3 minutes/hr	5%, consecutive 6-minute average	EPA PSD III BACT and 8/29/97 permit revision.
	Diesel-fired Units EDG-31-2813 EDG-31-1501	20%, 3 min/hr	20%, consecutive 6-min. average	Opacity standards set by AK SIP limits [18 AAC 50.055(a)(1)]
PM	**Turbines** NGT-31-15101 NGT-31-15102 NGT-31-15301 NGT-31-15302 NGT-31-15303 NGT-31-15304	No limit	0.05 grains/dscf (3-hr avg.)	AK SIP [18 AAC 50.055(b)(1)]
	Heaters NGH-31-1401 NGH-31-1402	No limit	0.05 grains/dscf (3-hr avg.)	AK SIP [18 AAC 50.055(b)(1)]
	Diesel-fired Units EDG-31-2813 EDG-31-1501	No limit	0.05 grains/dscf (3-hr avg.)	AK SIP [18 AAC 50.055(b)(1)]
SO_2	**Turbines** NGT-31-15101 NGT-31-15102 NGT-31-15301 NGT-31-15302 NGT-31-15303 NGT-31-15304	25 ppm H_2S in fuel	No Limit	No BACT or other limit applies to fuel. No limits are necessary to manage increment given current fuel gas quality.
	Heaters NGH-31-1401 NGH-31-1402	25 ppm H_2S in fuel	No Limit	No BACT or other limit applies to fuel. No limits are necessary to manage increment given current fuel gas quality.
	Diesel-fired Units EDG-31-2813 EDG-31-1501	0.5% S in fuel	No limit	No BACT or other limit applies to fuel. No limits are necessary to manage increment given current liquid fuel quality.

Pollutant	Equipment Tag No.	Permit to Operate No. 9473-AA013 Limit	Operating/ Construction Permit No. AQ0170TVP01 Revised Limits[3] for Each Unit	Explanation
VOC	**Turbines** NGT-31-15101 NGT-31-15102 NGT-31-15301 NGT-31-15302 NGT-31-15303 NGT-31-15304	No limit	No limit	No BACT or other limits apply.
	Heaters NGH-31-1401 NGH-31-1402	No limit	No limit	No BACT or other limits apply.
	Diesel-fired Units EDG-31-2813 EDG-31-1501	No limit	No limit	No BACT or other limits apply.
Operational Restriction	**Diesel-fired Units** EDG-31-2813 EDG-31-1501	None	200 hrs/yr per unit owner requested limit	The ORL of Title V Operating/ Construction Permit AQ0170TVP01 Condition 25 of 200 hr/yr is rescinded in this renewal permit. The limit was used only to establish PTE for the emergency units. BPXA calculated PTE for these units based on 500 hours of operation per year per unit, consistent with EPA J. Seitz memo for an emergency unit dated September 6, 1995. The actual to projected actual provisions of both 40 CFR 52.21 and 18 AAC 50.502(c)(3)(B) results in zero change in emissions since there is no expected change in actual non-emergency operating time as a result of removing the limit. Removal of this ORL does not trigger a Title I modification nor PSD review.

The Department issued Construction Permit No. AQ0170CPT01 to this stationary source on August 13, 2009 for the Main Injection Pump Bundle Replacement Project. Operating/ Construction Permit No. AQ0170TVP01 Condition 24 was rescinded and replaced by the requirements of Conditions (2 through 4) of Construction Permit No. AQ0170CPT01. The stationary source-specific requirements established in this Title I permit are included in the renewal operating permit as described in

Table J.

Title V Operating Permit Application, Revisions and Renewal History

The Permittee submitted an application for a Title V operating permit in November 19, 1997 (concurrently with the construction permit application) and supplements to the application on January 20, 1998, April 28, 1998, and April 2, 2003. On October 27, 2003, the Department issued Operating/Construction Permit No. AQ0170TVP01. On February 17, 2004, the Department issued Revision 1 to Operating/Construction Permit No. AQ0170TVP01 to clarify the Department's decision on the aggregation issue for BPXA stationary sources and activities at the Prudhoe Bay Unit. This discussion is found under the heading "Seawater Injection Plant East Identification" of the Statement of Basis.

The Permittee submitted a permit renewal application on June 26, 2008. The Department issued a completeness determination letter for the application on August 21, 2008.

COMPLIANCE HISTORY

The stationary source has operated at its current location since 1981. Review of the permit files for this stationary source, which includes the past inspection reports and compliance evaluations, indicate that the Permittee was in violation of AS 46.14.130(a) and 18 AAC 50.306(a). The Permittee self-reported that they failed to obtain a construction permit prior to a major modification in the stationary source.

On August 9, 2007, the Department issued Notice of Violation No. 300.16.405, Enforcement Tracking No. 07-0347-40-6336, to BPXA. The notice stated that BPXA failed to obtain a construction permit prior to installation of new pump bundle on a pump driven by a Rolls Royce RB211 and Cooper Rolls RT56 power engine (EU ID 2). Based on analysis of turbine baseline emissions, the change to the new pump bundle would result in an increase in projected future actual emissions of NOx by more than the PSD significance level of 40 TPY. The compliance case is now closed with the issuance of a settlement agreement between the Department and BPXA on September 7, 2007 and Construction Permit No. AQ0170CPT01 on August 13, 2009.

APPLICABLE REQUIREMENTS 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).

Alaska's SIP included 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 after January 17, 1997; and
- Minor permits issued after October 1, 2004.

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. Table I and

Table J below list the requirements carried over from Permit to Operate No. 9473-AA0013, EPA PSD Permit No. PSD-X81-01, Operating/Construction Permit No. AQ0170TVP01 Revision 1, and Construction Permit No. AQ0170CPT01 into Operating Permit No. AQ0170TVP02 to ensure compliance with the applicable requirements.

Table I – Comparison of Previous Permit to Operate No. 9473-AA0013, PSD Permit No. PSD-X81-01, and Operating/Construction Permit No. AQ0170TVP01 Revision 1 Conditions to Operating Permit No. AQ0170TVP02 Conditions[4]

Permit No. 9473-AA0013 Condition No.	Description of Requirement	Permit No. AQ0170TVP02 Condition No.	How Condition was Revised	
			Operating/Construction Permit No. AQ0170TVP01	Operating Permit No. AQ0170TVP02
2 and Exhibit B	Comply with the most stringent of applicable emission standards and specifications set out in….and Exhibit B	1, 5, 8, 11, and 12	The Alaska SIP limits have been carried forward with amendments as listed in 18 AAC 50. Other limits have been carried forward without change or have been corrected, as stated in Table H of the Statement of Basis. BACT limits are from EPA PSD Permit No. PSD-X81-01 (PSD III) as revised 8/29/97.	Limits are carried forward as revised in Permit No. AQ170TVP01. Added Conditions 11.2 and 12.2 to gap-fill MR&R requirements for short-term emission limits.
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	8.1, 26.1.c	Incorporated the EPA-approved custom schedule and monitoring plan.	No additional change.
5 and Exhibit C	Fuel oil testing to determine the sulfur content of the liquid fuel burned in the equipment.	8.4, 8.6	Adopted the language used for standard condition for Sulfur Compound Emissions from Oil-Fired Fuel Burning Equipment (Standard Permit Condition XI, 18 AAC 50.346(c), 5/3/02).	Adopted the language used for standard condition for Sulfur Compound Emissions from Oil-Fired Fuel Burning Equipment for North Slope Diesel fuel and Other fuel oil (Standard Permit Condition XI, 18 AAC 50.346(c), 8/25/04).

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

Permit No. 9473-AA0013 Condition No.	Description of Requirement	Permit No. AQ0170TVP02 Condition No.	How Condition was Revised: Operating/Construction Permit No. AQ0170TVP01	How Condition was Revised: Operating Permit No. AQ0170TVP02
6 and Exhibit D	Calculate the total quantity of sulfur dioxide from the stationary source each month based on Condition 4 and 5 and report the result in the operating report.	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.	N/A
7 and Exhibit C	Install, maintain, and operate a monitoring device (fuel gas meter) to measure or estimate fuel consumption by the turbines. For other sources the fuel consumption may be estimated.	15	Similar requirements, different format.	Added monthly monitoring and recording of fuel consumption requirement for stationary source-wide in Condition 15.1.
None	Install, maintain, and operate in good working order a continuous emissions monitoring system (CEMS) for recording and monitoring EU IDs 7 and 8 flue gas content of CO or O_2…	13	Carried forward as revised in EPA PSD Permit No. PSD-X81-01 (PSD III), 8/29/97.	No change.
15 and Exhibit D	Submit quarterly operating reports	60	Same requirement.	Same requirement with a change in the required submittal deadline from 30 days to 45 days after the end of each reporting period.
16	Maintain records…for not less than one year, and…accessible to the Department for not less than three years.	55	Record retention is now five years per regulation. Standard condition.	No change.
17	Submit 18 AAC 50.110 showing by 11/30/95.	None	Requirement rescinded by the Department on 4/28/95.	N/A
Exhibit D, Item 3	Report the number of hours of operation for each emission unit and the total fuel consumption by emission unit group and the entire stationary source for each month.	14, 15	Similar requirements, different format.	Added monthly monitoring and recording of consecutive 12-month period summation of operational hours for each of EU IDs 1 – 10 in Condition 14.1. Added monthly

Permit No. 9473-AA0013 Condition No.	Description of Requirement	Permit No. AQ0170TVP02 Condition No.	How Condition was Revised	
			Operating/Construction Permit No. AQ0170TVP01	**Operating Permit No. AQ0170TVP02**
				monitoring and recording of fuel consumption requirement for stationary source-wide in Condition 15.1.
Exhibit D, Items 4 and 5	Report the high, low, mean, and standard deviation of the fuel gas H_2S and liquid fuel sulfur content annually	None	Condition has been deleted. The Department no longer requires this information.	N/A

Table J – Comparison of Construction Permit No. AQ0170CPT01 Conditions to Operating Permit No. AQ0170TVP02 Conditions[5]

Permit No. AQ0170CPT01 Condition No.	Description of Requirement	Permit No. AQ0170TVP02 Condition No.	How Condition was Revised
			Operating Permit No. AQ0170TVP02
2, 3, 4	EU IDs 1 and 2 operational limits and MR&R	9	Condition 24 of Permit No. AQ0170TVP01 Revision 1 was replaced and rescinded by Construction Permit No AQ0170CPT01 Conditions 2 through 4. This permit action replaced the requirement to provide "annual certification" to "certification" for possible inclusion with the operating report requirement.
5	Protect NO_2 increment by complying with Condition 3	10	No change.

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

STATEMENT OF BASIS FOR THE PERMIT CONDITIONS

The State and federal regulations for each condition are cited in Operating Permit No. AQ0170TVP02. The Statement of Basis provides the legal and factual basis for each term and condition as set forth in 40 C.F.R. 71.6(a)(1)(i).

Conditions 1 - 3, 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 – 10 are fuel-burning equipment and industrial processes.

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

Factual Basis: Condition 1 prohibits the Permittee from causing or allowing visible emissions in excess of the applicable standard in 18 AAC 50.055(a)(1). The Permittee shall not cause or allow the equipment to violate this standard.

The Permittee must monitor, record, and report (MR&R) emissions in accordance with Conditions 2 through 3 of the permit. MR&R conditions are standard conditions adopted into regulation pursuant to AS 46.14.010(e). These conditions have been modified in this permit as follows. The Department added a provision that clarifies the option to continue an established monitoring frequency for renewal permits.

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

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 PM emissions. However, the Department can request a source test for PM emissions from any smoking equipment.

Reporting – As provided for in Condition 1, the Permittee must certify that only gaseous fuels are used in the equipment.

Liquid Fuel-Fired Burning 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 has been removed from the permit. The condition applies to EU IDs 9 and 10. For the intermittently operated EU ID 10, the Permittee is required to do Visible Emissions observations by the Method 9 plan as detailed in Condition 2 if it operates more than 650 hours in any rolling 12-month period, or if replaced during the permit term. If EU ID10 becomes significant, the Permittee shall conduct Method 9 observations within 30 days of triggering change of status; i.e., if operating during that period, otherwise perform Method 9 observations during the next month EU ID 10 operates. 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 and record any actions taken to reduce visible emissions.

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

Insignificant Emission Units:

For EU ID 10 (emergency engine), the unit is insignificant for as long as it does not exceed the insignificant emissions thresholds in 18 AAC 50.326(e). The significant/insignificant status of EU ID 10 can be tracked through Conditions 14 and 15 which require monitoring of hours of operation and fuel consumption. The Permittee must annually certify compliance under Condition 61 with the opacity standard. If the insignificant operating hour threshold is exceeded, EU ID 10 will be subject to the VE MR&R in Conditions 2 through 4.

Conditions 5 - 7, Particulate Matter (PM) Standard and MR&R

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

- EU IDs 1 – 10 are fuel-burning equipment and industrial processes.

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

Factual Basis: Condition 5 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 6 through 7.

Gas-Fired Fuel Burning Equipment:

For gas-fired emission units, EU IDs 1 – 8, MR&R conditions are Standard Permit Condition VIII adopted into regulation pursuant to AS 46.14.010(e). The Department determined that these standard conditions adequately meet the requirements of 40 C.F.R. 71.6(a)(3). No emission unit or stationary source operational or compliance factors indicate that unit-specific or stationary-source specific conditions would better meet these requirements. Therefore, the Department concluded that the standard conditions meet the requirements of 40 C.F.R. 71.6(a)(3).

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

Liquid Fuel-Fired Burning Equipment:

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.

For liquid fuel units, EU IDs 9 and 10, the MR&R conditions are Standard Permit Condition IX adopted into regulation pursuant to AS 46.14.010(e). The Department determined that these standard conditions adequately meet the requirements of 40 C.F.R. 71.6(a)(3). No emission unit or stationary source operational or compliance factors indicate that unit-specific or stationary-source specific conditions would better meet these requirements. Therefore, the Department concluded that the standard conditions meet the requirements of 40 C.F.R. 71.6(a)(3).

Insignificant Emission Units:

For EU ID 10 (emergency engine), the unit is insignificant for as long as it does not exceed the insignificant emissions thresholds in 18 AAC 50.326(e). The significant/insignificant status of EU ID 10 can be tracked through Conditions 14 and 15 which require monitoring of hours of operation and fuel consumption. The Permittee must annually certify compliance under Condition 61 with the PM standard. If the insignificant operating hour threshold is exceeded, EU ID 10 will be subject to the PM MR&R in Conditions 6 through 7.

Condition 8, Sulfur Compound Emissions

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 – 10 are fuel-burning equipment and industrial processes.

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 SO_2 emission standard.

Liquid Fuels:

For oil fired fuel burning equipment, EU IDs 9 and 10, the MR&R conditions are Standard Permit Conditions XI and XII adopted into regulation pursuant to AS 46.14.010(e). These conditions have been modified in this permit as follows. The Department corrected Condition 8.6.b(i) to replace the text *"...method listed in 18 AAC 50.035 or an alternative method approved by the Department"* with *"...method listed in 18 AAC 50.035(b)-(c) or 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1)"*. The text *"...or an alternative method approved by the Department"* was discarded during the Revised Action Plan submitted to EPA on July 15, 2007, as a result of the EPA Audit of the September 2006 Title V Program Review. This text is not to be used in subsequent permits since it allows a

Permittee to bypass the public process for changing monitoring requirements by submitting off-record requests to change monitoring methods.

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

Gaseous Fuels:

Fuel gas sulfur is measured as hydrogen sulfide (H_2S) concentration in ppm by volume (ppmv). Methane-based 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 at the North Slope of Alaska and is not projected to be available during the life of this permit.

Condition 8.1.b requires the Permittee to conduct a monthly analysis for the fuel gas H_2S content using either ASTM D4084, D5504, D4810, D4913, D6228 or GPA Standard 2377, or a listed method approved in 18 AAC 50.035(b)-(c) or 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1).

The 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 monthly statement from the fuel supplier or the sulfur content analysis with the operating report.

Conditions 9 - 15, Title I Permit Requirements

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

Factual Basis: The Permittee originally requested operational limits for EU IDs 1 and 2 in Condition 24 of Permit No. AQ0170TVP01 to avoid classification as PSD major modification. The requested restriction pertains to recent and potential future like-in-kind replacements of RB211-24A turbines with RB211-24C turbines. The RB211-24A to RB211-24C turbine replacements are considered like-in-kind because the "C" configuration turbines operate using existing "A" configuration control parameters (i.e., maximum firing temperature of 680° C), and are subject to the same mechanical drive limitations (i.e., maximum pump pressure at rated flow) that prevent the "C"-configured turbines from achieving their maximum rated horsepower. The Permittee agreed to request that the maximum firing temperature restriction be included in Permit No. AQ0170TVP01. The result of this restriction is that potential emissions are kept consistent with those that existed before the replacement, hence, avoiding the need to comply with the modification requirements under a construction permit. The original version of the PSD avoidance provision was included as Condition 24 of Permit No. AQ0170TVP01.

On August 9, 2007, the Department issued a notice of violation (NOV) to BPXA due to violation of AS 46.14.130(a) and 18 AAC 50.306(a) for failure to obtain a construction permit prior to installation of new pump bundle on a pump driven by a Rolls Royce RB211 and Cooper Rolls RT56 power engine (EU ID 2). The NOV was issued by ADEC in response to correspondence initiated by BPXA in a June 8, 2007 letter from BPXA to ADEC in which discovery of a potential violation of federal New Source Review rules was disclosed. This change constitutes a major modification in the stationary source because based on analysis of turbine baseline emissions, the change to the new pump bundle would result in an increase in projected future actual emissions of NOx by more than the PSD significance level of 40 TPY. The new pump bundle was removed soon after the discovery was made by BPXA.

The case was resolved through a settlement agreement between the Department and BPXA, submittal of a PSD permit application by BPXA on December 13, 2007, and the issuance of Construction Permit No. AQ0170CPT01 on August 13, 2009. The permit application served two purposes – 1) to meet the required PSD permit application requirements of 18 AAC 50.306(a); and 2) to revise Condition 24 of Permit No. AQ0170TVP01 under the permit application provisions of 18 AAC 50.508(6). The intent of the application under 50.508(6) was to revise Condition 24 of the previous Title V permit to reflect the capacity of the turbine rather than the pump and to make the condition enforceable from a practical matter. Additional details are provided in the Technical Analysis Report (TAR) for permit AQ0170CPT01. The PSD permit application for this project did not require completion of a BACT analysis because the project did not result in a "modification" to any existing emission unit. The pump bundle replaced in EU IDs 1 and 2 is not integral to the emission unit, which in this case is the turbine. Correspondence dated September 30, 2008 from ADEC to BPXA and provided with the TAR for permit AQ0170CPT01 explains the Department's position regarding why a BACT analysis was not required.

In conjunction with the application under 18 AAC 50.508(6), the previous owner requested PSD avoidance limit was made practically enforceable and changed to reflect the capacity of the turbine by deleting the horsepower limit at 29,070 Hp at ISO conditions and instead restricting the fuel heat consumption to no more than an average of 235.0 MMBtu/hr in any 12 month rolling period be added[6]. The power turbine inlet temperature limit of 680 °C was retained._These revised and retained PSD avoidance limits and corresponding MR&R are now reflected in Condition 9 which replaces Condition 24 of Permit No. AQ0170TVP01.

[6] Although not the primary intent of the pump replacement project (which was to replace worn parts), the pump bundle changeout removed a bottleneck created by the capacity of the previous pump bundle. The intent of the original PSD avoidance was retained through modification of the owner-requested limit to allow the Permittee to operate the turbine up to, but not in excess of, the full capacity of a RB211-24A turbine. This is now tracked using fuel consumption as the parameter to confirm that operation of any RB211-24C installed at the stationary source does not exceed the capacity of the originally permitted RB211-24A turbines.

Condition 10 is also carried forward from Construction Permit No. AQ0170CPT01 to protect ambient air quality standards.

Conditions 11 and 12 are EPA BACT limits. Between 1979 and 1981, EPA Region 10 issued four PSD permits for Prudhoe Bay stationary sources. Of these permits, Permit PSD-X81-01 issued December 17, 1980 authorized construction of BPXA SIPE turbines and heaters. 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 was 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 EPA changes are explained as follows. For EU IDs 1 – 8, ton per year emission limits apply for NOx and CO. For NOx and CO, EPA also established short-term BACT emission limits in other terms (i.e. ppm, lb/MMscf, or lb/MMBtu). The EPA revisions were incorporated into the initial Title V Operating/Construction Permit No. AQ0170TVP01 Revision 1 and carried forward to this renewal Title V Operating Permit AQ0170TVP02. The Department removed the footnotes from the BACT emission tables that explained that limits were full load since the EPA permit amendment does not contain this exception.

The Permittee is required to calculate and report emission levels for NOx and CO for EU IDs 1 – 8. Monitoring in Conditions 11.2 and 12.2 are added as gap-fill requirements for compliance with the short-term BACT emission limit for NOx and are identical to that for Subpart GG turbines. Despite being gas fired, which normally requires no VE observation, the Department has imposed an annual VE observation requirement in Condition 11.2.b. Once a baseline of information regarding compliance with the BACT limit is accumulated during the 5-year term of this permit, the Permittee can make a case for relaxation of the VE requirement upon renewal.

Condition 13 is carried forward from EPA permit PSD-X81-01 (PSD III), which included a requirement to conduct CO or O_2 monitoring for heaters rated at greater than 43 MMBtu/hr using a continuous emissions monitoring system (CEMS) or in accordance with an approved periodic monitoring plan. Some of the heaters originally affected by this requirement have been decommissioned at SIPE. However, the requirement still applies to EU IDs 7 and 8 (Broach heaters). This requirement was not included in the previous Permit to Operate No. 9473-AA013, but is carried forward from the EPA permit. The Permittee submitted a proposed periodic monitoring plan on November 27, 1984. The Department approved the plan on March 15, 1985. The rationale for the monitoring program is to ensure good operation and maintenance of the heaters and to comply with the BACT requirements for CO. Other related correspondence pertaining to approval of the periodic monitoring plan are dated January 7, 1985, February 4, 1985, April 6, 1985, and May 10, 1985.

Conditions 14 and 15 are requirements from Permit to Operate No. 9473-AA013 that must be carried forward to this renewal Title V permit. These conditions contain requirements to measure fuel consumption and operating hours. A provision for recording and reporting the consecutive 12-month operating time was added to Condition 14 due to various requirements within the permit which are triggered based on an annual operating time threshold.

Condition 16, 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 conditions re-iterate the emission standards and require compliance for insignificant emission units. The Permittee may not cause or allow their equipment to violate these standards. 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 these conditions.

Condition 16.4.a requires certification that the units did not exceed State emission standards during the previous year and did not emit any prohibited air pollution. For EU ID 10, as long as it does not exceed the insignificant emissions thresholds in 18 AAC 50.326(e), it is considered an insignificant unit and no monitoring is required.

Conditions 17 – 24, NSPS Subpart A Requirements

Legal Basis: The Permittee must comply with the applicable New Source Performance Standard (NSPS) provisions incorporated by reference effective July 1, 2007, for specific industrial activities, as listed in 18 AAC 50.040[7].

Most affected facilities (with the exception of some storage tanks) subject to an NSPS are subject to Subpart A. At this stationary source, EU IDs 1 – 6 are subject to NSPS Subpart GG and therefore subject to Subpart A.

Conditions 17.1 through 17.3 - The Permittee has already complied with the notification requirements in 40 C.F.R. 60.7 (a)(1) - (4) for EU IDs 1 – 6. However, the Permittee is still subject to these requirements in the event of a new NSPS affected facility[8] or in the event of a modification or reconstruction of an existing facility[9] into an affected facility.

Condition 17.4- The requirements 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 18 - 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 19 and 20 - NSPS excess emission reporting requirements and summary report form in 40 C.F.R. 60.7(c) & (d) are applicable to affected units that use a continuous

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

[8] *Affected facility* means, with reference to a stationary source, any apparatus to which a standard applies, as defined in 40 C.F.R. 60.2, effective 7/1/07.

[9] *Existing facility* means, with reference to a stationary source, any apparatus of the type for which a New Source Performance Standard 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 7/1/07.

monitoring device (none required at the Seawater Injection Plant East) and for turbines subject to Subpart GG that use periodic sulfur monitoring requirement in Condition 26.1.a. 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.

Condition 21 - The Permittee has already complied with the initial performance test requirements in 40 C.F.R. 60.8 for EU IDs 1 – 6. However, the Permittee is still subject to these requirements in the event of a new NSPS affected facility, in the event of a modification or reconstruction of an existing facility into an affected facility or at such other times as may be required by EPA.

Condition 22 - 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 1 – 6).

Condition 23 - states that any credible evidence may be used to demonstrate compliance or establishing violations of relevant NSPS standards for EU IDs 1 – 6.

Condition 24 - Concealment of emissions prohibitions in 40 C.F. R. 60.12 are applicable to EU IDs 1 – 6.

Recordkeeping requirements in 40 C.F.R. 60.7(f) are applicable to all NSPS affected facilities. (Satisfied by Condition 55)

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.

Conditions 25 - 26, NSPS Subpart GG Requirements

Legal Basis: These conditions prohibit the Permittee from exceeding emission standards set out in Subpart GG. NSPS Subpart GG applies to stationary gas turbines with a heat input at peak load (maximum load at 60 percent relative humidity, 59 °F, and 14.7 psi) equal to or greater than 10.7 gigajoules per hour (10 MMBtu/hr), based on the lower heating value of the fuel fired and constructed, modified, or reconstructed after October 3, 1977. EU IDs 1 - 6 are subject to NSPS Subpart GG.

Factual Basis: These conditions incorporate NSPS Subpart GG NOx emission and sulfur compound limits. The Permittee may not allow equipment to violate these standards. Per Condition 26.1.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 26.1.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 and 10/18/93) and Alternate H_2S Sampling Method (10/2/97) allowing the Permittee to determine the fuel 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. Reporting is not required if a demonstration is made that the gaseous fuel burned by the affected turbines meets the definition of natural gas in 40 C.F.R. 60.331(u). 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.

EU IDs 3 – 6 were manufactured after the applicability date of October 3, 1977 for 40 C.F.R. 60, Subpart GG. These turbines are subject to NSPS Subpart GG requirements for sulfur dioxide standard under §60.333 but are not subject to the NOx standard under 40 C.F.R. 60.332(a) because they were manufactured prior to October 3, 1982 and therefore meet the exemption criteria in 40 C.F.R. 60.332(e). Pursuant to 40 C.F.R. 60.332(e), stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have commenced construction prior to October 3, 1982 are exempt from 40 C.F.R. 60.332(a).

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

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

Where:

STD_{NO_x} = allowable NOx emissions (percent by volume at 15 percent oxygen and on a dry basis)

Y = manufacturer's maximum rated heat input (kJ/W-hr), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the affected stationary source. The value of Y shall not exceed 14.4 kJ/W-hr; and

F = NOx emissions allowance for fuel bound nitrogen, percent by volume, assumed to be zero for 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 NOx standard is 208 ppmvd for EU IDs 1 and 2.

SO_2 Standard: The Permittee is required to comply with one of the following sulfur requirements for EU IDs 1 – 6 (turbines):

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

(2) do not cause or allow the sulfur content for the fuel burned in EU IDs 1 – 6 to exceed 0.8 percent by weight.

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

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

Conditions 25.2 - 25.4, NOx Monitoring, Recordkeeping, and Reporting

Legal Basis: Periodic monitoring, recordkeeping, and reporting are included in Condition 25.2 through 25.4 for all turbines that normally operate for greater than 400 hours in a 12 month period. This additional monitoring is necessary to ensure that turbine emissions comply with the applicable BACT and NSPS NOx 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.

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 or Subpart GG NOx emission limits will inherently comply with the limit at all times and will never need additional testing. After a sufficient body of NOx data is gathered under monitoring conditions for compliance with BACT 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 NOx monitoring conditions. The Department may determine that to assure compliance it is necessary to retain or increase the current monitoring frequency. Per EPA letter dated August 19, 1996, the EPA has granted the Permittee waivers from monitoring fuel-bound nitrogen for the Prudhoe Bay, Eastern Operating Area (EOA), Kuparuk River Unit Central Processing Facility (CPF-1) and the Greater Pt. McIntyre facilities in Alaska since the stationary sources burn pipeline quality natural gas. However, 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 NOx emission standard of the subpart per 40 C.F.R. 60.332(a)(3) & (4) and §60.334(h)(2). The Permittee has not used this option; therefore, fuel-bound nitrogen monitoring is not required even without a 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 NOx emissions at less than or equal to 90 percent of the limits shown in Conditions 11 and 25, then periodic monitoring is required at the first applicable of three criteria: either within 5 years of the last performance test, or within a year of the issue 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. For clarification, the Department added a 6 month cut-off date for triggering source testing within 1 year after the permit issue date in accordance with Condition 25.2.a(i)(B). The 6-month trigger identifies when Condition 25.2.a(i)(C) would be enacted to require source testing within 1 year of triggering 400 hours. This ensures that a unit would not appear to be out of compliance with Condition 25.2.a(i)(B) once it finally triggered Condition 25.2.a(i)(C).

If the most recent performance test showed operations at greater than 90 percent of any of the emissions listed in Conditions 11 and 25, 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[10]" 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 25.2.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 NOx measurements. The time at each point is to be at least one minute plus the average response time of the instrument. The recorded value is the average steady state response. Presumably, the steady state response would exclude some or all of the response time of the instrument. Three runs are to be done at each test load.

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

Conditions 26.1 - 26.4, 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 this condition 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.

[10] *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 7/1/07.

Monitoring: Condition 26.1 incorporates NSPS Subpart GG fuel sulfur monitoring requirements. Per 40 C.F.R. 60.334(h)(3), the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in 40 C.F.R. 60.331(u), regardless of whether an existing custom schedule approved by the Administrator requires such monitoring. Therefore, no monitoring of total sulfur content is necessary for EU IDs 1 – 6 if they burn natural gas. The Permittee may submit a certified statement to the Department indicating that the fuel gas combusted at the stationary source meets the definition of natural gas in 40 C.F.R. 60.331(u), pursuant to 40 C.F.R. 60.334(h)(3).

The Permittee was granted an EPA-approved Custom Fuel Monitoring Schedule (7/13/93 and 10/18/93) and Alternate H_2S Sampling Method (10/2/97) allowing the Permittee to determine the fuel 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. Per Condition 26.1.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.

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 55.

Reporting: NSPS Subpart GG fuel sulfur reporting requirements, as established under the approved custom fuel monitoring schedule for gas fired units, are incorporated in the permit in Condition 26.4. According to the custom fuel monitoring schedule approved in correspondence dated October 18, 1993, the Permittee is required to submit results of fuel gas H_2S monitoring to EPA at least annually.

For the purpose of the EEMSP reports and summary report required under 40 C.F.R. 60.7(c) and (d) and stated in Conditions 19 and 20, the Permittee is required to report as excess emissions any period during which the sulfur content of the fuel being fired in the turbine exceeds 0.8 percent. As of 7/1/07 (the adoption date of 40 C.F.R. 60 by the State of Alaska as of the effective date of this permit), Subpart GG 40 C.F.R. 60.334(j)(5) requires EEMSP reporting 30 days after the end of each 6-month period, but the alternative monitoring schedule approved for SIPE reduces the required frequency of these reports to at least annually. As stated in Conditions 19, 20, and 59, reports are to be submitted to the Department and EPA, and summarized in the operating report required under Condition 60. However, per Conditions 26.1.b and 26.4.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.

Condition 26.4.b requires copies of the results from the monitoring requirements in Condition 26.1 be included in the operating report required under Condition 60. State excess emissions and permit deviation reports are to be submitted in accordance with Condition 26.4.c.

Conditions 27 - 29, 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 30, 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 31 - 32, 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). Except for the modification noted in the last paragraph of this "Factual Basis", the Department determined that these standard conditions adequately meet the requirements of AS 46.14.250. No emission unit or stationary source operational or compliance factors indicate that unit-specific or stationary-source specific conditions would better meet these requirements. Therefore, the Department concluded that the standard conditions meet the requirements of AS 46.14.250.

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

The assessable emissions are potential emissions or projected emissions of each air pollutant equal to or greater than 10 tons per year 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.

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

The Department modified the standard condition to correct Condition 32.2 such that it referenced "submitted" (i.e., postmarked) rather than "received" in accordance with the timeframe of Condition 32.1.

Condition 33, Good Air Pollution Control Practice

Legal Basis: This condition ensures compliance with the applicable requirement in 18 AAC 50.346(b)(5) and applies to all emission units, **except** those subject to federal emission standards, those subject to continuous emission or parametric monitoring, and for insignificant emission units, i.e., except EU IDs 1 – 6, and 10 (if the unit remains insignificant).

Factual Basis: The condition requires the Permittee to comply with good air pollution control practices for all units.

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

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 34, 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 35, 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 will engage in industrial activity at the stationary source.

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

Condition 36, 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 at a 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 37, Air Pollution Prohibited

Legal Basis: This condition ensures compliance with the applicable requirement in 18 AAC 50.110. The condition prohibits the Permittee from causing any emission which is injurious to human health or welfare, animal or plant life, or property, or which would unreasonably interfere with the enjoyment of life or property. Air Pollution Prohibited requirements apply to the stationary source because the stationary source will have emissions.

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

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

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

Condition 38, 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 59. Excess emission reporting under Condition 81 requires information on the steps taken to minimize emissions. Monitoring of compliance for this condition consists of the report required under Condition 59.

Condition 39, 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 40, NESHAPs Applicability Determinations

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

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

Condition 41, Refrigerant Recycling and Disposal

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

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

Conditions 42 - 43, Halon Prohibitions

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

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

Condition 44, Open Burning

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

Factual Basis: The Permittee has stated that no open burning is conducted at this stationary source. However, the Permittee may conduct open burning by following the provisions of regulation or by following the Department guidelines posted at the website http://www.dec.state.ak.us/air/ap/applic.htm. The open burning state regulation in 18 AAC 50.065 applies to the Permittee if the Permittee conducts open burning at the stationary source. No specific monitoring is required for this condition. More extensive monitoring and recordkeeping is not warranted because the Permittee does not conduct open burning as a routine part of their business.

Condition 45, 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 November 30, 2001.

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 46 - 48, 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 to conduct source tests by this permit. The Permittee is required to conduct source tests as set out in Conditions 46 through 48.

Factual Basis: These conditions supplement the specific monitoring requirements stated elsewhere in this permit. Compliance monitoring with Conditions 46 through 48 consist of the test reports required by Condition 53.

Condition 49, Test Exemption

Legal Basis: This condition ensures compliance with the applicable requirement in 18 AAC 50.345(a) and applies when the 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 50 - 53, Test Deadline Extension, Test Plans, Notifications and Reports

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

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

Condition 54, 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: The condition incorporates a regulatory requirement for PM source tests. This condition supplements specific monitoring requirements stated elsewhere in this permit.

Condition 55, 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 56, 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 of November 30, 2001.

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

Condition 57, 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 58, Information Requests

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

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

Condition 59, 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 revised Standard Operating Permit Condition III to include a provision to allow at least 30 days to report a permit deviation that is not also classified as excess emissions (e.g., failure to report, incomplete reports, etc.) under new Condition 72.1c(ii). In addition, the Department has clarified the final provision of the standard condition at the request of the Permittee. Since the underlying requirement is unchanged, but is only stated differently, the request to revise the standard permit condition language was granted by the Department._The Department also made a correction to the Standard Operating Permit Condition III to allow identical reporting methodology for both Excess Emissions and Permit Deviations reports which use identical forms and should have identical submissions methods. The Department also made an allowance to submit permit deviations not classified as excess emissions within 30 days of the end of the month that the deviation is discovered since the deviation cannot be reported absent discovery, or no later than the next Annual Compliance Certification report in Condition 61 since reasonable inquiry should lead to a discovery of any permit deviations. Beyond as noted above, the Department has determined that the standard conditions adequately meet the requirements of 40 C.F.R. 71.6(a)(3). No additional emission unit or stationary source operational or compliance factors indicate the unit-specific or stationary-source-specific conditions would better meet the requirements. Therefore, the Department concludes that the standard conditions as modified meets the requirements of 40 C.F.R. 71.6(a)(3).

Section 14, Notification Form

The Department modified the notification form contained in Standard Permit Condition IV in a revised rulemaking dated August 20, 2008 to more adequately meet the requirements of Chapter 50, Air Quality Control. The rulemaking for these changes took effect November 9, 2008. The modification consisted of correcting typos and moving "Failure to Monitor/Report" and "Recordkeeping Failure" to Section 2 - permit deviations.

Condition 60, 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 the Standard Permit Condition VII as adopted into regulation on August 20, 2008 pursuant to AS 46.14.010(e). The Department has made a correction to the Standard Permit Condition VII by changing the number of copies of documents to be submitted from "an original and two copies" to "an original and one copy". As requested by the Permittee, the Department also revised the condition to allow quarterly operating reports 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 standard condition as modified to allow for more reporting adequately meets the requirements of 40 C.F.R. 71.6(a)(3).

Condition 61, 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 61.2 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. This change more adequately meets the requirements of 18 AAC 50 and agency needs, as the Department can more efficiently distribute the electronic copy to staff in other locations.

Condition 62, NSPS and NESHAP Reports

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

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

Condition 63, 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 64 - 66, 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 under18 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 64.

Condition 67, Permit Renewal

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

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

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

Conditions 68 - 72, 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 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 73 - 74, Permit Shield

Legal Basis: These conditions ensure compliance with the applicable requirement in 18 AAC 50.326(j) and apply because the Permittee has requested that the Department shield the source from the inapplicable requirements listed under this condition under the Federally approved State operating program effective November 30, 2001

Factual Basis: Table D of Operating Permit No. AQ0170TVP02 shows the permit shield that the Department granted to the Permittee. 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.

The Department based the determinations on the permit application, past operating permit, Title I permits, and inspection reports.

ATTACHMENT A

Figure 1 -- Summary Report -- Excess Emission and Monitoring System Performance

Pollutant (Circle One—SO_2/NO_X/fuel sulfur)

Reporting period dates:

From ____________ to ____________

Company: ____________

Emission Limitation: ____________

Address: ____________

Monitor Manufacturer and Model No.: ____________

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

Process Unit(s) Description: ____________

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

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

[1] For opacity, record all times in minutes. For gases, record all times in hours.

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

On a separate page, describe any changes since last quarter in CMS, process or controls. I certify that the information contained in this report is true, accurate, and complete.

____

Name

____

Signature