UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

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OFFICE OF
AIR QUALITY PLANNING
AND STANDARDS

MEMORANDUM

SUBJECT: Interpretation of "Ambient Air" In Situations Involving Leased Land Under the Regulations for Prevention of Significant Deterioration (PSD)

FROM: Stephen D. Page, Director Steve Page
Office of Air Quality Planning & Standards (C404-04)

TO: Regional Air Division Directors
Regions I-X

This memorandum responds to various inquiries about the Environmental Protection Agency's (EPA's) interpretation of the definitions of "ambient air" and "building, structure, facility, or installation" (as applied to air quality analyses under the Prevention of Significant Deterioration (PSD) program.[1] The inquiries pertain to the need by a PSD permit applicant to conduct a source impact analysis at particular locations.[2] Requests for this guidance on EPA's interpretation of the regulations generally have involved leasing arrangements where a source locates on land being leased to them by another source, and one source or the other must demonstrate compliance with ambient air standards. In some cases, the companies involved may be under some form of common ownership or control; in other cases, there is no apparent relation between the companies other than the leasing agreement. This memo and the supporting attachment describe EPA's interpretation of the applicable regulations under both scenarios.

The PSD source impact analysis involves the use of air quality dispersion models to predict the impact of a proposed PSD source's emissions (and other sources' emissions, where applicable) on pollutant concentrations in the ambient air. "Ambient air" is defined as "that portion of the atmosphere, external to buildings, to which the general public has access." The modeled prediction is used to determine whether the proposed source will cause or contribute to a violation of an ambient air standard, including any national ambient air quality standard (NAAQS) or PSD increment. A source is not required to model the impacts of its emissions at locations that are not

[1] The terms "ambient air" and "building, structure, facility, or installation" are defined at 40 CFR 50.1(e), and 40 CFR 52.21(b)(6), respectively.
[2] See 40 CFR 52.21(k) Source Impact Analysis.

considered to be ambient air. *See*, In the Matter of Hibbing Taconite Company, 2 E.A.D. 838 (Adm'r 1989). Accordingly, this guidance addresses which locations a source may exclude from the source impact analysis for purposes of PSD.

As a threshold matter, in order to identify the boundary between a source and ambient air in a leased-land scenario, it is important to determine whether you are dealing with one source or two (or more) sources. The determination of whether there is a single source or separate sources is based on the definition of "building, structure, facility, or installation" in our regulations.

With respect to a particular source, EPA's practice has been to exempt only an area from ambient air when the source (1) owns or controls the land or property; and (2) precludes public access to the land or property using a fence or other effective physical barrier. In the case of a leasing situation where there are two separate sources, the above conditions should be applied separately to both the lessor and the lessee(s).

In summary form, EPA interprets the regulations as follows in each of the ambient air scenarios set forth below:

1. When, under the existing business relationship, two (or more) operating companies constitute a single source:
   - If there is a barrier preventing public access, the air over the entire property (including the leased portion) is not ambient air to either the property owner (lessor) or the lessee.
   - In the absence of a barrier preventing public access, the air is ambient air for both the lessor and the lessee.

2. When two (or more) companies operate separate sources on property owned by one company and leased in part to the other, and the lessor retains control over public access to the entire property and actually maintains a physical barrier around it to preclude public access:
   - The air over the entire property (including the leased portion) is not ambient air to the lessor.
   - The air over the non-leased portion of the property is ambient air to the lessee.
   - The air over the leased portion is ambient air to the lessee unless the lessee undertakes its own separate action to preclude public access.

3. When two (or more) companies operate separate sources on property owned by one company and leased in part to the other, and the lessor grants the lessee sole control over who may access the leased property (e.g., leased property with direct access via entrance on outer perimeter of lessor's land):
   - The air over the property retained for use by the lessor is not ambient air to the lessor if public access is precluded.
   - The air over the lessor property is ambient air to the lessee.
   - The air over the leased property is ambient air to the lessor.

- The air over the leased property is ambient air to the lessee unless the lessee acts to preclude public access to the leased property.

4. When the property owner agrees to allow a lessee to operate a business on the leased land that is open to the general public (such as a restaurant, retail store, or office building) the outdoor areas that are accessible to the public, such as parking areas and entrances would be ambient air to the lessor and the lessee.

A more complete description of the relevant issues concerning "ambient air" and "single source," which are important to the scenarios summarized above, is contained in the attachment to this memo.

Neither the memo nor the attachment should be regarded as a substitute for the applicable regulations, nor are they regulations in themselves. This memorandum does not announce any change in EPA's interpretation of the cited regulations, but rather summarizes prior interpretative statements and provides guidance to the Regions on how to apply EPA's interpretation of the regulations to the particular circumstances described.

Attachment

ATTACHMENT
Support Document

As a threshold matter, in order to identify the boundary between a source and ambient air in a leased-land scenario, it is important to determine whether you are dealing with one source or two (or more) sources. The determination of whether there is a single source or separate sources is based on the definition of "building, structure, facility, or installation" in sections 51.166(b)(6) and 52.21(b)(6) of the PSD regulations. This defined phrase is contained in the definition of "stationary source" in sections 51.166(b)(5) and 52.21(b)(5). The boundary between each stationary source and ambient air is then based on the definition of ambient air in section 50.1(e) of EPA's regulations. In scenarios where there is potentially a separate source within the boundaries of land owned by another source, the answer to the ambient air question is closely related to the question of whether there are one or two sources involved. In the following, we will address both the "single source" and "ambient air" questions together.

Under a business relationship involving two or more companies (one a lessor, the other a lessee) where the three criteria used to determine a single source scenario have been met, and a physical barrier is in place to preclude access to the general public, the air over the entire property may be excluded from ambient air by both the lessor and lessee for PSD purposes. However, as explained below, the situation may change as a result of possible future changes in the business relationship between the lessor and the lessee. We will address each of the potential scenarios below after outlining the general principles that EPA would apply under its interpretation of the regulations.

A. Single or Separate Source Analysis

According to EPA's definition, "a 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). Thus, pollutant-emitting activities are generally considered part of a single stationary source when these activities are (1) part of the same industrial grouping (as determined by applicable SIC codes), (2) contiguous or adjacent, and (3) under common control. In several guidance documents, EPA has recognized that one or more of these criteria can be satisfied when an emissions unit serves in a supporting role for a primary activity at a nearby location.

When two companies meet the first two criteria, i.e., within the same industrial grouping (operations are classified in the same major group), and properties are immediately contiguous and adjacent to each other, the principal question that needs to be answered is whether the issue of common control is affected by potentially changing business relationships. A case-by-case evaluation is usually required to determine if common control is present. Even where facilities have separate legal owners, EPA has found that common control may be established on the basis of a contract, which creates a support or dependency relationship through which one facility may have effective control over the other. See Letter from Richard R. Long, EPA Region 8 to Julie Wrend, Colorado Department of Public Health regarding "Single Source Determination for Coors/TriGen" (Nov. 12, 1998). We consider separately-owned sources to be under common control if one source is able to "exercise restraining or directing influence over," "have power over," "have power of authority to guide or manage," or "regulate economic activity over" the other by virtue of their contractual relationship. See Letter from William Spratlin, EPA Region 7 to Peter Hamlin, Iowa Department of Natural Resources re Common Control (September 18, 1995).

If one plant is purchasing supplies and services on the open market and accepts delivery from a number of different suppliers in minority proportions, then there would typically be no basis for a common control determination. Therefore, as long as traditional commodity transactions occur at arms length, the two companies would likely not be considered to be under common control for permitting purposes. On the other hand, if one source executes a contractual agreement with an adjacent or contiguous source to provide the bulk of its output, then it may be more difficult to demonstrate that the two entities are not under common control.

B. Ambient Air Analysis - Single Source

"Ambient air" is defined at 40 CFR 50.1(e) as "that portion of the atmosphere, external to buildings, to which the general public has access." EPA's longstanding interpretation has been that "exemption from ambient air is available only for the atmosphere over land owned or controlled by the source and to which public access is precluded by a fence or other physical barrier." Letter from Administrator Douglas M. Costle, EPA to

Senator Jennings Randolph, Chairman, Environment and Public Works Committee (Dec. 19, 1980).

With respect to a particular source, EPA's practice has been to allow the source to exempt from the source impact analysis areas that are not considered to be ambient air. That is, an area may be excluded when the source - (1) owns or controls the land or property; and (2) precludes public access to the land or property using a fence or other effective physical barrier. Under the first condition described above, "control" of the land means that the source has certain rights to the use of the land/property, including the power to control public access to it. Under the second condition, a source must actually take the necessary steps to preclude[1] the general public from accessing the property by relying on some type of physical barrier (such as a fence, wall or a natural obstruction). Where the appropriate barrier does not exist to prevent access by the general public, the air over the property should be regarded as ambient air for PSD purposes.

An internal leasing arrangement between a lessor and another business entity is not relevant if the facilities are considered one source. In such cases, the ambient air for both would begin at the fence line of the lessor if it controls the land and precludes access to the property.

C. Ambient Air Analysis - Separate Sources

In the case of a leasing situation where there are two separate sources, the above conditions are applied separately to both the lessor and the lessee(s). Consistent with this concept, EPA has stated that, for a source operating on leased property (the lessee), "ambient air is considered to exclude only the atmosphere over that land leased and controlled by the source." See "SO_2 Guideline," EPA-450/2-89-019, page 2-6, (October 1989); Memorandum from G.T. Helms, OAQPS, to W.S. Baker, Air Branch Chief, Region II (July 27, 1987). This means that the lessee must, in addition to controlling the leased property, actually preclude public access to that property.

When the lessor retains control over public access to the entire property and actually maintains a physical barrier around it to preclude public access, our interpretation is that the air

[1] "Preclude" does not necessarily imply that public access is absolutely impossible, but rather that the likelihood of such access is small.

over the entire property, including the leased portion, is not ambient air to the lessor, because the two key conditions are being satisfied by the lessor with respect to the entire property in question. However, if the lessor grants the lessee sole control over who may access the leased property and the lessee is the one who maintains the physical barrier around it, then the air over the leased property should be treated as ambient air by the lessor. This is further explained below.

1. Leased parcel within lessor's property

Where the leased land is within the confines of the lessor's property (i.e. not on the outer boundary) and the lessor maintains the power to exclude the general public from the leased land, and does so through reliance on a physical barrier, then we do not consider the leased land to be ambient air with respect to the lessor. An example of this situation would be a case where a company leases land on its plant site to another company or a joint venture but (1) the first company, as the lessor, continues to control access onto the entire parcel of property through a gate staffed by its employees or agents; and (2) the terms of the lease agreement preclude the lessee from permitting the general public to enter the property (including the leased land). Under these conditions, ambient air is the portion of the atmosphere external to the property owned by the lessor. The entire property, including that portion leased to another source, is excluded from ambient air to the extent that the host source adequately precludes public access to such property.

With respect to the lessee, the air over the leased property is not ambient air if the lessee precludes the general public (including employees of, or invitees to, the lessor's property) from accessing the leased property through the use of a physical barrier separate from the one used by the lessor. If the lessee does not use a physical barrier (i.e. erect a fence) to preclude the general public from accessing the leased land, then even the leased land is ambient air with respect to the lessee.[2]

2. Leased parcel on outer boundary of lessor's land

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[2] For example, EPA has said that "for sources operating on leased property, ambient air is considered to exclude only the atmosphere over that land leased and controlled by the source [lessee]." SO_2 Guideline (October 1989). Herein, "controlled" is taken to mean that the lessee adequately controls access to its leased portion.

Where the leased parcel is on the outer boundary of the lessor's land and the lessee (not the lessor) controls a separate gate or access point onto the leased land, EPA's interpretation is that the leased land is ambient air to the lessor for PSD purposes. Thus, under these circumstances, leased land is ambient air to the lessor because the lessor has granted the power to exclude public access to the lessee and the lessor does not preclude public access. The same would be true in a situation where the lessor permits a lessee to operate a business on the leased land that is open to the general public (such as a restaurant, retail store, or office building). The outdoor areas of these businesses that are accessible to the general public, such as parking lots and entrances would be ambient air to the lessor. Consistent with the analysis described earlier, these areas would also be ambient air to the lessee if the lessee does not maintain physical barriers to exclude the general public from the leased property.

3. General public and business invitees

An important component of the general principles described above is the concept of "general public." We consider this term generally to include anyone who is not employed by or under control of the lessor, but, more specifically, persons who do not require lessor's permission to be on the property. Based on the latter condition, the general public may not include mail carriers, equipment and product suppliers, maintenance and repair persons, as well as persons who are permitted to enter restricted land for the business benefit of the person who has the power to control access to the land. For example, contractors or delivery persons that are expressly granted access to a plant site by the lessor are not the general public, but instead are considered "business invitees."

Where part of the owned property is leased to another source, employees of the lessee source are considered business invitees of the lessor source as are those who seek visitation rights to the lessee. Both must have the lessor's permission to be on the property (e.g., attain approved access via a security gate). However, a business invitee of the lessor is not necessarily a business invitee of a lessee. Thus, EPA considers the business invitee of the lessor to be part of the general public with respect to the lessee, unless it is agreed that the lessee also invites that person onto the leased land for the benefit of the lessee's business.

The general public includes customers of a business to which access is typically not restricted during business hours. For example, the customer of a restaurant or other retail business is a member of the general public even if the proprietor restricts public access during non-business hours by locking the entrance to the property. Thus, if a business leasing land from a host source depends upon the patronage of such persons as described above during the normal course of business, then the lessor should consider accessible outdoor areas on the leased land to be ambient air. For example, EPA previously considered leased land occupied by an office building to be ambient air for the lessor.

The general public also includes persons who are frequently permitted to enter restricted-access land for a purpose that does not ordinarily benefit the "business." For example, EPA has treated athletic facilities within the restricted fence line of a source as ambient air when persons unconnected to the business were regularly granted access for sporting events (which do not necessarily benefit a business). However, EPA would not consider an area within a fence line to be ambient air based on de minimis levels of public access, such as where a source on rare occasions allows persons without a business connection to the source onto its land for a family or community-oriented event (i.e. a picnic or fair held once a year).

D. Examples Concerning "Ambient Air" Under Various Business Relationships

Where the operations of two companies--company A (the lessor) and company B (the lessee)--meet the three criteria necessary to be considered a single source, the lessor and lessee may exclude the entire property from ambient air for PSD purposes follows. For example, common control would be established if company A held a controlling interest in company B, e.g., company A owns 51 percent of company B. Since the activities are conducted on the property by a single source, the focus of the ambient air analysis is on whether the operator of that one source has ownership or control of the land and maintains a physical barrier around the property. Under the current scenario, company A has ownership and control over all the land involved, has erected a fence around its property to exclude the general public, and permits only employees and business invitees of either company A or company B to enter the property. Thus, the lessor (company A) and the lessee (company

B) may exclude the entire property owned by company A from ambient air for PSD purposes.

Under a scenario where company A and company B own interests in a joint venture (company C) located on company A's land and company A sells its interest in the joint venture to company B, the single source determination and the ambient air analysis could change. If company C is now owned entirely by company B due to the sale and there is no contractual relationship between company A and company C, this would be sufficient to break the "common control" prong of the single source test. Thus, if company C and company A now operate separate sources but company C continues to lease land from company A, we would conduct the ambient air analysis for separate source described above. For example, if company C occupies a leased parcel within the boundaries of company A's land, and company A will continue to have exclusive control over access to company A's land and the leased property occupied by company C, even if the common control prong is broken and company A and company C operate separate sources, company A may continue to exclude all the land inside company A's boundary (including the land leased to company C) from ambient air. However, company C would not be allowed to exclude all of Company A's land from ambient air. If company C maintains a physical barrier that excludes the employees and business invitees of company A from the leased parcel, then company C could exclude the leased parcel from ambient air but not the surrounding land owned by company A because company C does not control access to Company A's property. The employees and business invitees (not otherwise linked to company C) of company A are considered general public with respect to company C. The analysis presented in this paragraph assumed that company A's sale of its interest in company C, and the lack of any continued contractual relationship, makes the operations of these two companies into separate sources.

However, the common control prong may not be broken if (after the sale of the company A's joint venture interest to company B) company C and company A retain a close business relationship. For example, if company A and company C continue to maintain certain contractual relationships even after the sale of company A's interest to company B, the contractual relationships may cause the two companies to be regarded as one source. For instance, company C may continue to be obligated to provide feedstock to Company A. Alternately, company A may continue to provide company C a number of facility services integral to the operations of company C. Thus, there may be sufficient information to conclude that company A and company C will be under common control by virtue of either an exclusive contract for service relationship or a support or dependency relationship that effectively gives one entity control over both company A and company C. Accordingly, a single source, comprised of company A and company C, may exclude the atmosphere over the entire fenced property from ambient air considerations for PSD purposes.

Under a different example, companies A and B may be negotiating the extent to which company A will continue to be involved in the operational aspects of company C's business after the sale of company A's interest to company B. At one facility, company C could continue to be operated by the employees of company A or its subsidiary. At the other facility, the employees of company A that formerly worked for the joint venture would become sole employees of company C. These relationships could affect the determination of whether these sources are separate sources or a single source. For example, if company C is operated by employees of company A, company A and company C may be regarded as a single source because the arrangement makes company C dependent upon company A for labor to operate the facility, such that company A effectively controls company C. If company C is operated by its own employees, this arrangement would not provide grounds to establish common control. With respect to the ambient air issue, these relationships by themselves are not directly relevant unless the common control test is broken and company A and company C operate separate sources. If company C's facility is operated by its own employees and the sources are otherwise separate, then company A's employees would be considered general public with respect to company C while on company A's property. However, if the sources are separate and company A's employees are permitted access to company C's leased land to provide a limited range of services to company C (not amounting to complete operation of the facility), the EPA would consider the employees of company A to be business invitees of company C and not part of the general public when on the land controlled by company C.

An agreement between company A and company C to be treated as a single source for purposes of "major source" consideration is typically not enough to consider the two sources as one. Whether or not the two facilities constitute a single source is determined based on a review of the facts under the three prong-test described above. An agreement between two entities to treat a source as a single source by itself is not material if the facts indicate that the sources are separate sources. However, the parties may agree to structure their business arrangement in a particular way so that the facts show that the operations of company A and company C constitute a single source. Thus, assuming this is case, the single source status would be relevant to determining the boundary between the source and ambient air, as discussed above.

Finally, if company A and company C agree to "joint security control" over the area of Company C's leasehold and company A's site, this could be relevant if the two are separate sources, but not if the two companies operations are considered a single source. If there are two sources, this could be relevant if company A is granting company C the power to permit the general public to enter the property. If "joint security control" means that company A gives company C the power to allow any member of the general public onto company A's property, then EPA would consider A to have given up control over the owned property. However, if "joint security control" means that company C has a limited right to allow a business invitee of company C onto the property of company A for purposes of accessing company C's property, then company A would still retain control over the property and would not be authorizing company C to allow the general public onto the property. Under such a scenario, company C's business invitees are also business invitees of company A. Accordingly, the location of ambient air for each source would be determined using the analysis described above for separate sources.

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR PERMITS PROGRAM

TECHNICAL ANALYSIS REPORT
For Air Quality Control Minor Permit No. AQ0181MSS04

BP Exploration (Alaska) Inc. (BPXA)
Endicott Production Facility

ENDICOTT PRODUCTION FACILITY DRILL RIG AND PERMIT HYGIENE

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Date: Final – March 03, 2009

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TABLE OF CONTENTS

1.0 Introduction 4
1.1 Stationary Source Description 4
1.2 Permit History 4
1.3 Application Description 5
1.4 Emissions Summary and Permit Applicability 6
1.5 Department Findings 8
2.0 Permit Conditions 9
2.1 Requirements for all Minor Permits. 9
2.2 Requirements for a Minor Permit for Air Quality Protection 9
2.3 Requirements for a Minor Permit that Revises or Rescinds a Previous Title I Permit 11
2.4 Requirements for a Minor Permit establishing an ORL 14
2.5 Recordkeeping, Reporting, and Certification Requirements 14
2.6 New Source Performance Standards (NSPS) 14
2.7 Terms to make Permit Enforceable 14
3.0 Permit Administration 14
Modeling Review Memorandum dated 12/12/08 17

ABBREVIATIONS/ACRONYMS

AAC ....Alaska Administrative Code
ADEC ....Alaska Department of Environmental Conservation
AS.................................Alaska Statutes
ASTM............................American Society of Testing and Materials
BPXA ....BP Exploration (Alaska) Inc.
CEMS ....Continuous Emission Monitoring System
C.F.R. ....Code of Federal Regulations
COMS............................Continuous Opacity Monitoring System
EPA ....Environmental Protection Agency
NA ....Not Applicable
NAICS ....North American Industry Classification System
NESHAPS ....National Emission Standards for Hazardous Air Pollutants
NSPS ....New Source Performance Standards
PSD................................Prevention of Significant Deterioration
PTE................................Potential to Emit
RM.................................Reference Method
SIC.................................Standard Industrial Classification
SN..................................Serial Number
TAR...............................Technical Analysis Report
TBD...............................To Be Determined

Units and Measures

bhp................................brake horsepower or boiler horsepower
gr./dscf..........................grains per dry standard cubic feet (1 pound = 7,000 grains)
dscf ....dry standard cubic foot
gph.................................gallons per hour
kW ....kiloWatts
kW-e..............................kilowatts electric[1]
lbs ....pounds
mmBtu...........................million British Thermal Units
ppm................................parts per million
ppmv..............................parts per million by volume
tph..................................tons per hour
tpy..................................tons per year
wt%................................weight percent

Pollutants

CO ....Carbon Monoxide
HAPS.............................Hazardous Air Pollutants
H_2S ....Hydrogen Sulfide
NO_X ....Oxides of Nitrogen
NO_2................................Nitrogen Dioxide
NO ....Nitric Oxide
PM-10............................Particulate Matter with an aerodynamic diameter less than 10 microns
S.....................................Sulfur
SO_2 ....Sulfur Dioxide
VOC ....Volatile Organic Compound

[1] kW-e refers to rated generator electrical output rather than engine output

1.0 Introduction

This Technical Analysis Report (TAR) provides the Alaska Department of Environmental Conservation's (Department's) basis for issuing Air Quality Control Minor Permit No. AQ0181MSS04 to BPXA for the Endicott Production Facility (Endicott). This minor permit authorizes the operation of up to two concurrent transportable drilling rigs at Endicott and removes the hourly operational limits on two existing emission units. This minor permit also re-establishes and revises conditions from initial Operating/Construction Permit No. AQ0181TVP01originally established in Permit Nos. 9773-AC011, Amendment No. 3 and pre-1997 Permit-to-Operate 9573-AA029.

1.1 Stationary Source Description

Endicott is located off the coast of the North Slope of Alaska, in the Beaufort Sea, about 37 miles from Prudhoe Bay. Endicott consists of three man-made islands: the main production island (MPI) (located 3.8 miles offshore), Endeavor Island (located near MPI), and the satellite drilling island (SDI) (located three miles southeast of MPI.

At Endicott, BPXA processes crude oil production fluids (crude oil, hydrocarbon gas, and water) from various crude oil accumulations located on the North Slope of Alaska. BPXA processes the crude oil to remove hydrocarbon gas and water in order to meet specific crude oil sales specifications. The energy to support operations comes primarily from combustion of produced hydrocarbon gas; however, BPXA also uses fuel oil in some equipment.

Endicott is classified as Prevention of Significant Deterioration- (PSD) Major stationary source.

1.2 Permit History

Prior to issuance of AQ0181MSS04, BPXA operated Endicott under the following active permits, in order of issue date:

Construction Permit No. 9773-AC011, Amendment No. 3, issued November 13, 2002 (Title I). The Department revised portions of this Title I permit in initial Operating/Construction Permit No. 181TVP01. The Department considers Permit No. 9773-AC011, Amendment No. 3 rescinded by initial Operating/Construction Permit No. 181TVP01. This was not explicitly stated in initial Operating/Construction Permit No. 181TVP01. This has been a source of confusion with both BPXA and the Department acting as if Permit No. 9773-AC011, Amendment No. 3 was still active. The Department is explicitly rescinding Permit No. 9773-AC011, Amendment No. 3 through AQ0181MSS04 to avoid any further confusion.

Operating/Construction Permit No. 181TVP01, issued October 14, 2003 (Title V) and revised through August 7, 2006 (Revision 2). The initial permit is an operating/construction permit, which included Title I provisions and revised Title I provisions of Construction Permit No. 9773-AC011, Amendment No. 3 and pre-1997 Permit-to-Operate No. 9573-AA029. Revision 2 of Permit AQ0181TVP01 incorporates provisions from AQ0181MSS02. Permit AQ0181TVP01, Revision 2 expired on November 13, 2008. Therefore the Department is re-establishing the Title I conditions/revisions of Permit No. 9773-AC011, Amendment No. 3 and pre-1997 Permit-to-Operate No. 9573-AA029 that occurred ONLY in the initial operating/ construction permit. These are Conditions 3 through 15 in the initial operating/construction permit.

Minor Permit No. AQ0181MSS02, issued July 24, 2006 (Title I). The Department is rescinding this permit upon issuance of AQ0181MSS04. The Department revised Permit No. 9773-AC011, Amendment No. 3 through AQ0181MSS02. The title I provisions in initial Operating/Construction Permit 181TVP01 superseded the Title I provisions in Permit No. 9773-AC011, Amendment No. 3. The Department did not clarify this in Permit AQ0181MSS02, but is now correcting that oversight. AQ0181MSS04 contains all applicable requirements of AQ0181MSS02.

1.3 Application Description

BPXA requested that the Department authorize the concurrent operation of up to two transportable drill rigs as follows:

1. Doyon 14 drill rig (Doyon 14) and Doyon 16 drill rig (Doyon 16) operating concurrently at MPI during February through April for a maximum of 75 days per drill rig.
2. Doyon 14 and Doyon 16 operating concurrently at SDI during February through April for a maximum of 75 days per drill rig.
3. Doyon 14 and Doyon 16 operating concurrently with the Liberty drill rig[2] (Liberty) at SDI during February through March for a maximum of 45 days per drill rig (excluding Liberty).
4. Doyon 14 operating concurrently with Liberty at SDI during February through April for a maximum of 75 days (excluding Liberty).
5. Doyon 16 operating concurrently with Liberty at SDI during February through April for a maximum of 75 days (excluding Liberty).

BPXA requested that the Department revise Permit No. 9773-AC011 Amendment No.3 (some of which the Department revised when incorporated into the initial operating/construction permit) as follows:

1. Remove the Doyon 15 drill rig from the emission unit inventory, this drill rig is no longer at Endicott and will not be used in the future.
2. Revise the emission unit inventory to reflect revised equipment tag numbers, revised emission units and revised operating limits.
3. Revise the potential emissions to reflect emissions based on updated AP-42 emission factors and specific heat rates for the turbines.
4. Revise the sulfur monitoring requirements required by 40 CFR 60, Subpart GG to reflect the revised Subpart GG requirements.

[2] The Liberty Drill Rig authorized in Permit No. AQ0181CPT06.

5. Remove the annual hourly operational restrictions for the portable emergency generator and the portable air compressor (Emission Units 21 and 22 as listed in Table 1 of Operating Permit AQ0181TVP01, Revision 2).
6. Change all relevant references of "facility" to "stationary source" and change all relevant references of "source" to "emission unit."
7. Additional permit hygiene changes.

BPXA requested that the Department revise conditions originally established in the pre-1997 Permit-to-Operate No. 9573-AA029 and subsequently incorporated into initial Operating/Construction Permit No. AQ0181TVP01as follows:[3]

1. Change all relevant references of "facility" to "stationary source" and change all relevant references of "source" to "emission unit."
2. Revise the monitoring requirements for the Process Heaters. This requirement was originally established in Exhibit C of Permit to Operate No. 9573-AA029 and was revised when incorporated into initial Operating/Construction Permit AQ0181TVP01as Condition 14.

BPXA requested that the Department revise Permit No. AQ0181MSS02 as follows:

1. Revise the emission unit tag numbers in several conditions.
2. Rescind conditions no longer necessary with removal of the annual hourly operational restrictions for the portable emergency generator and the portable air compressor
3. Additional permit hygiene changes

1.4 Emissions Summary and Permit Applicability

Table 1 shows the proposed Potential to Emit (PTE) in tons per year (tpy) of the drill rig boilers and heaters (Units 69 through 74 in Table 1 of Permit AQ0181MSS04) with the owner requested limit (ORL) on the number of days of drill rig operation to protect ambient air quality. The drill rig engines are not included in the PTE because they are classified as non-road engines and their emissions do not count toward permit applicability.

BPXA's PTE calculations for the drill rig boilers and heaters in the application included the following assumptions.

1. Continuous annual operation.

[3] As described in the findings, the Department is re-establishing in Permit No. AQ0181MSS04 the Pre-1997 Permit-to-Operate No. 9573-AA029 conditions revised in the initial operating/construction permit.. (This does not change any applicable requriments for BPXA and will clarify the Title I permit basis for the provisions, as the initial construction/operating permit expired in November of 2008.) The Department does not have to rescind that **actual** Permit 9573-AA029, because it expired when it was subsumed into the iniital operaing/construction permit, but the Department will revise all citations. The Department will also retain the TAR for Permit-to-Operate 9573-AA029 and the Statement of Basis for the operating permit in the AQ00181MSS04 permit docket for reference.

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2. AP-42 emission factors for Nitrogen Oxides, Carbon Monoxide, Particulate Matter with an aerodynamic less than 10 microns, and Volatile Organic Compounds (NO_X, CO, PM-10 and VOC, respectively).
3. Sulfur Dioxide (SO_2) emissions calculated by mass balance with diesel fuel sulfur limited to 0.1 weight percent Sulfur (wt% S)

The Department corrected BPXA's assumption of continuous annual operation and recalculated the PTE based on continuous operation for an annual maximum of 75 days. This is the maximum number of days a drill rig can operate in one year based on the ORL. BPXA also included credits for the removal of emission units and the recalculation of PTE because of updated emission factors for existing emission units when they determined permit applicability. BPXA cannot take credit for this decrease in PTE when determining permit applicability for the current project.

As shown in Table 1 this project is not classified under 18 AAC 50.502(c)(3) when taking into account the ORL to protect ambient air quality. As shown in Table 2 this project would be classified under 18 AAC 50.502(c)(3) without the ORL to protect ambient air quality.

BPXA's PTE calculations for the drill rig engines in the application include the following assumptions.

1. Continuous operation for 75 days annually.
2. AP-42 emission factors for NO_X, CO, PM-10 and VOC.
3. SO_2 emissions calculated by mass balance with diesel fuel sulfur limited to 0.0015 weight percent Sulfur (wt% S)

Table 3 shows the stationary source's assessable emissions due to the operation of the drill rigs, which includes the drill rig engines.

Table 1 – Endicott Minor Permit Applicability with ORL, tpy

Pollutant	NO_X	CO	PM-10	VOC	SO_2
PTE Units 69 through 74 (Drill Rig Heaters and Boilers)	3.4	0.7	0.3	0.0	2.4
Change	3.4	0.7	0.3	0.0	2.4
Minor Permit Threshold	10	N/A	10	N/A	10
Minor Permit?	No	N/A	No	N/A	No

Table 2 – Endicott Minor Permit Applicability without ORL, tpy

Pollutant	NO_X	CO	PM-10	VOC	SO_2
PTE Units 69 through 74 (Drill Rig Heaters and Boilers)	16.5	3.3	1.4	0.2	11.8
Change	16.5	3.3	1.4	0.2	11.8
Minor Permit Threshold	10	N/A	10	N/A	10

Minor Permit?	Yes	N/A	No	N/A	Yes

Table 3– Endicott Stationary Source Change in Assessable Emissions Summary, tpy

Pollutant	NO_X	CO	PM-10	SO_2	VOC	Total Assessable
PTE Units 69 through 74 (Drill Rig Heaters and Boilers)	3.4	0.7	0.3	2.4	0.0	6.8
PTE Drill Rig Engines (Non-road engines)	229.3	52.2	5.1	0.1	7.9	294.6
PTE for drill rigs	232.7	52.9	5.4	2.5	7.9	301.4

1.5 Department Findings

The Department made the following findings regarding BPXA's application:

(1) Revising the existing Title I permit conditions described in the application requires a minor permit under 18 AAC 50.508(6).

(2) The authorization of the transportable drill rigs described in the application requires a minor permit under 18 AAC 50.502(c)(2).

(3) The ORL to restrict the number of days of operation of the drill rigs to protect ambient air quality requires a minor permit under 18 AAC 50.508(5). This ORL also avoids project classification under 18 AAC 50.502(c)(3).

(4) The Department established the existing annual hourly operational restrictions for the portable emergency generator and the portable air compressor to protect ambient standards and increments. The authorization of the portable drill rigs requires an analysis for ambient air quality standards for NO_X, PM-10 and SO_2. BPXA supplied an ambient analysis as part of their application, as required under 18 AAC 50.540(k)(3) and 18 AAC 50.540(c)(2)(B) which demonstrates compliance with the ambient air quality standards and increments.

(5) Units 69 through 74 (drill rig boilers and heaters) are subject to state Air Quality Control regulations 18 AAC 50.055(a)(1) for visible emissions, 18 AAC 50.055(b)(1) for particulate matter, and 18 AAC 50.055(c) for sulfur compound emissions. The drill rig engines are classified as non-road engines by BPXA and are not subject to these regulations. BPXA's compliance with the ORL will ensure the drill rig engines retain their non-road engine status.

(6) The revisions described in the application to existing emission units including removal of emission units and revised emission factors will cause a decrease in annual stationary source-wide NO_X, PM-10, SO_2, and CO PTE. The revisions will

also cause an increase in stationary source-wide VOC. The Department will not revise the stationary source wide assessable PTE listed in Condition 1 of Operating/Construction Permit No. AQ0181TVP01, Revision 2.

(7) Permit AQ0181TVP01, Revision 2 expired on November 13, 2008. Therefore the Department is re-establishing the Title I conditions/revisions of Permit No. 9773-AC011, Amendment No. 3 and pre-1997 Permit-to-Operate No. 9573-AA029 that occurred ONLY in the initial operating/ construction/ permit. These are Conditions 3 through 15 in the initial operating/construction permit.

(8) Endicott is located in the North Slope Borough coastal district. This project is consistent with the Alaska Coastal Management Program (ACMP) through AS 46.40.040(b)(1). The Department did not notify the local district and resource agencies of the permit action to request additional ACMP review because the North Slope Borough Coastal District does not have a final plan in effect at this time. The Department notified the local district and resource agencies of their opportunity to comment on the preliminary permit during the public notice.

2.0 Permit Conditions

2.1 Requirements for all Minor Permits.

As described in 18 AAC 50.544(a), each minor permit issued under 18 AAC 50.542 must identify the stationary source, the project, the Permittee, and contact information, and the requirement to pay fees.

The permit cover page identifies the stationary source, the project, the Permittee, and contact information as required in 18 AAC 50.544(a)(1). The permit contains a requirement to pay fees as required in 18 AAC 50.543(a)(2). The Department will not update the operating permit assessable emissions through this minor permit. The assessable emissions for the drill rigs are 301 tpy, as shown in Table 3. BPXA must pay this assessable emission fee in addition to any fees required by the Title V permit. The Department notes that the PTE in the existing Title V permit for NO_X, CO, VOC, PM-10, and SO_2 are all above ten tons per year, so all of the emissions from this project are assessable.

2.2 Requirements for a Minor Permit for Air Quality Protection

As required under 18 AAC 50.544(c), each minor permit classified under 18 AAC 50.502(c) must contain

(1) terms and conditions as necessary to ensure that the source will not cause or contribute to a violation of an ambient standard,

(2) performance tests for state emission limits, and

(3) maintenance requirements according to the manufacturer's or operator's maintenance procedures.

2.2.1 Ambient Air Quality Analysis

See Section 2.3.1.

2.2.2 State Emission Standards

BPXA requested that the Department incorporate this minor permit into the Title V operating permit as an administrative amendment, therefore the Department included the on-going monitoring, recordkeeping, and reporting (mr&r) that would be necessary for a Title V operating permit or under the Compliance Assurance Monitoring Rule for state emissions standards.

2.2.2.1 Visible Emission Standard

New Units 69 through74 are fuel-burning equipment subject to the state standard for visible emissions in 18 AAC 50.055(a)(1).

BPXA did not provide a demonstration that Units 69 through 74 will comply with the state standard, however these units are subject to on-going mr&r. The Department will accept the first demonstration under the on-going mr&r as the initial compliance demonstration.

2.2.2.2 Particulate Matter Standard

New Units 69 through74 are fuel-burning equipment subject to the state standard for PM emissions of 0.05 grains per dry standard cubic foot of exhaust gas (gr./dscf) in 18 AAC 50.055(b)(1).

BPXA provided an initial compliance demonstration in the application for Units 69 through 74. In their initial compliance demonstration, BPXA used 40 CFR 60, Method 19. These units are still subject to the on-going mr&r despite the initial compliance demonstration.

2.2.2.3 Sulfur Dioxide Standard

New Units 69 through74 are fuel-burning equipment subject to state standards for SO_2 in 18 AAC 50.055(c).

BPXA provided an initial compliance demonstration in the application for Units 69 through 74. In their initial compliance demonstration BPXA used 40 CFR 60, Method 19 to show that if a fuel sulfur content less than 0.74 weight percent sulfur is used in the emission units they will comply with the state standard for SO_2. These units are still subject to the on-going mr&r despite the initial compliance demonstration.

2.2.3 Maintenance Requirements

As described in 18 AAC 50.544(c)(3), the permit must include maintenance of equipment according to manufacturer's or operator's maintenance procedures, keep records, and keep a copy of the maintenance procedures.

2.3 Requirements for a Minor Permit that Revises or Rescinds a Previous Title I Permit

As described in 18 AAC 50.544(i) a minor permit classified under 18 AAC 50.508(6) must contain terms and conditions as necessary to ensure that the permittee will construct and operate the stationary source in accordance with 18 AAC 50.

2.3.1 Ambient Air Quality Requirements

BPXA submitted an ambient air quality modeling assessment to demonstrate that they can comply with the Alaska Ambient Air Quality Standards (AAAQS) listed in 18 AAC 50.010 and the maximum allowable increases (increments) listed in 18 AAC 50.020 while operating the drill rigs and removing the annual hourly operational limits on the existing emission units. The Department reviewed the modeling assessment and concurs that the revisions authorized by Minor Permit No. AQ0181MSS04 will comply with the AAAQS and the increments listed in 18 AAC 50.020. The Department's review of the assessment is included in Appendix A of this TAR.

The Department has included operational limits and fuel sulfur restrictions on the drill rigs in the minor permit to protect ambient standards and increments. The Department has also included stack height requirements on emission units authorized in Permit No. AQ0181CPT06 in the minor permit to protect ambient standards and increments.

2.3.2 Conditions re-established from initial Operating/Construction Permit No. AQ0181TVP01

In this permit the Department is re-establishing conditions from initial Operating/Construction Permit No. AQ0181TVP01, that carried forward or revised conditions originally established in Permit No. 9773-AC011, Amendment No. 3. The Department is also re-establishing conditions from initial Operating/Construction Permit No. AQ0181TVP01 that revised conditions originally established in Pre-1997 Permit to Operate No. 9573-AA029.

Tables B through N in the Permit No. AQ0181TVP01, Revision 1 Statement of Basis (SOB) describe the conditions from Permit No. 9773-AC011, Amendment No. 3 and Pre-1997 Permit to Operate No. 9573-AA029 that were carried forward or revised by conditions in initial Operating/Construction Permit No. AQ0181TVP01. As described in the SOB Conditions 3 through 16 in the initial Operating/Construction Permit No. AQ0181TVP01 contain the Title I provisions of Permit No. 9773-AC011, Amendment No. 3 and Pre-1997 Permit to Operate No. 9573-AA029. The Department re-established these conditions in Section 5 of Permit No. AQ0181MSS04 with the exception of Condition 16. The Department did not re-establish Condition 16 because the shut down provisions were rescinded by Permit No. AQ0181MSS02.

2.3.2.1 Revisions to Permit No. 9573-AA029

This pre-1997 permit has expired, and the Department incorporated some conditions into initial Operating/Construction Permit No. AQ0181TVP01, which was a combined construction/operating permit. (It was subsequently revised, but the revision was not a Title I action.). BPXA requested the monitoring requirements for the process heaters originally established in Exhibit C of Permit to Operate No. 9573-AA029 be revised from once per month to once every 30 days the heaters operate. As revised and incorporated into Condition 14 in

Operating/Construction Permit No. AQ0181TVP01, Revision 2, Condition 14 requires monitoring not less than once during any month the heaters operate. The Department modified this condition as requested by BPXA in Section 5 of Permit No. AQ0181MSS04.

2.3.3 Revisions to Permit No. 9773-AC011, Amendment No. 3.

BPXA requested several revisions to Permit No 9773-AC011, Amendment No. 3 including the following:

(1) Revise Exhibits D and E to include revised emission units, emission unit tag numbers, emission factors, operating limits and potential emissions. BPXA requested that the new transportable drill rig heaters and boilers be incorporated into Exhibits D and E.

(2) Revise several conditions to include updated unit tag numbers.

(3) Revise several conditions that refer to the Portatest flare, this emission unit is no longer at Endicott.

(4) Remove the Doyon 15 drill rig emission units from Exhibit D and E. The drill rig is no longer at Endicott.

(5) BPXA requested Condition VI.B.4 be updated to include new sulfur monitoring requirements under 40 CFR 60 Subpart GG and included suggested language. The Department rescinded the entire Condition VI.B and included conditions consistent with the Subpart GG language in the Department's Operating Permits in Section 6 of Permit No. AQ0181MSS04 rather than using BPXA's suggested language.

Because Initial Operating/Construction Permit No. 181TVP01 Title I provisions superseded the Title I provision in Permit No. 9773-AC011, Amendment No. 3 the Department cannot directly revise conditions from Permit No. 9773-AC011, Amendment No. 3. However, the conditions in Section 5 of Permit No. AQ0181MSS04 fulfill many of BPXA's requested revisions. Table 4 summarizes the Department's incorporation of BPXA's requested revisions to Permit No. 9773-AC011, Amendment No. 3 into Permit No. AQ0181MSS04

Table 4 – Summary of BPXA's requested revisions to Permit No. 9773-AC011, Amendment No. 3 into Permit No. AQ0181MSS04

Permit No. 9773-AC011, Amendment No. 3 requested revision	Description of how incorporated in Permit No. AQ00181MSS04
Revise III.G	Condition previously rescinded in initial operating/construction permit. Incorporated into operating report condition in Section 8.
Revise IV.A and IV.B	Conditions previously rescinded in initial operating/construction permit Tag numbers updated in Section 5 conditions.
Revise VI.B, VI.B.4, VI.B.5a, and VI.B.5b	Conditions previously rescinded in initial operating/construction permit, established Subpart GG conditions in Section 6.

Revise VII.A	This condition was revised by Conditions 3 and 4 in initial operating/construction permit. Conditions 3 and 4 re-established in Section 5 with BPXA's requested revision.
Rescind VII.C.1	Conditions previously rescinded in initial operating/construction permit.
Revise VII.C.3	This condition was revised by Conditions 5.1 and 5.2 in initial operating/construction permit. Conditions 5.1 and 5.2 re-established in Section 5 with BPXA's requested revision.
Revise VII.C.4	This condition was revised by Condition 13 in initial operating/construction permit. Condition 13 re-established in Section 5 with BPXA's requested revision.
Revise Conditions IX.A.1.b, IX.A.1.c, IX.A.1d, IX.A2.a, IX.A.2b, IX.A.3, IX.B, IX.B.1, IX.C, and IX.C.1	These conditions were revised by Conditions 9 and 15 in initial operating/construction permit. Conditions 9 and 15 re-established in Section 5 with BPXA's requested revision.
Revise Conditions X.A.1.a(1), X.A.1.b(1), X.B, X.C.1, X.D.1(b), X.D.1(e), and X.E.1	These conditions were revised by Condition 8 in initial operating/construction permit. Condition 8 re-established in Section 5 with BPXA's requested revision.
Revise Exhibits D and E	Exhibits D and E were incorporated into the emission unit inventory and Conditions 3 through 15 of the initial operating/construction permit. Conditions 3 through 15 re-established in Section 5 along with an updated emission unit inventory with BPXA's requested revisions. The updated PTE is not an enforceable limit and was not included.

2.3.4 Revisions to Permit No. AQ0181MSS02

The Department is rescinding Permit No. AQ0181MSS02 and incorporating the conditions in Permit No. AQ0181MSS04. The Department carried forward the Permit No. AQ0181MSS02 Title I conditions as shown in Table 5.

Table 5 – Description of AQ0181MSS02 conditions carried forward in Permit No. AQ0181MSS04

AQ0181MSS02 Condition Number	Description of how carried forward
1	Excess emissions reporting condition included in AQ0181MSS04, All 9773-AC011, Amendment No. 3 conditions rescinded by AQ0181MSS04
2	Incorporated into the Section 5 conditions
3	All 9773-AC011, Amendment No. 3 conditions rescinded by AQ0181MSS04
4	All 9773-AC011, Amendment No. 3 conditions rescinded by AQ0181MSS04
5 and 6	Incorporated into the Section 5 conditions.

7 and 8	These conditions are no longer needed due to removal of these emission units under current permit action.
9	Incorporated into the Section 5 conditions.
10	Incorporated into the Section 5 conditions

Additionally, BPXA requested that Condition 16 (Operating Reports) be revised to allow the submittal of operating reports within 45 days following the end of the reporting period. Because BPXA's request is not prohibited under 40 CFR 71.6 the Department included BPXA's request in the Operating Report condition in Permit No. AQ0181MSS04.

2.4 Requirements for a Minor Permit establishing an ORL

As required in 18 AAC 50.544(a)(4), this minor permit includes the applicable ORL requirements of 18 AAC 50.225.

2.4.1 ORL for ambient air quality protection and to avoid classification under 18 AAC 50.502(c)(3)

The minor permit contains the operating restrictions on the drill rigs to protect ambient air quality standards and increments. These operating restrictions also avoid the project being classified under 18 AAC 50.502(c)(3). The minor permit also contains mr&r conditions to ensure compliance with the ORL.

2.5 Recordkeeping, Reporting, and Certification Requirements

All air quality control permits must contain procedures for recordkeeping, reporting, and certification.

Certification and information request requirements are specifically required by 18 AAC 50.200 and 18 AAC 50.205, respectively.

2.6 New Source Performance Standards (NSPS)

Because the Department is incorporating AQ0181MSS04 as an administrative amendment to the Title V permit, the Department included the current subpart A and ubpart GG requirements.

2.7 Terms to make Permit Enforceable

The minor permit contains additional requirements as necessary to ensure that the permittee will construct and operate the stationary source or modification in accordance with 18 AAC 50, as described in 18 AAC 50.544(i).

3.0 Permit Administration

Some of the provisions of Minor Permit AQ0181MSS04 alter or relax existing limits contained in Operating Permit 181TVP01. Therefore, BPXA must still operate under the existing annual hourly operational limit for the portable emergency generator and portable air compressor (Emission Units 21 and 22 as listed in Table 1 of Operating Permit AQ0181TVP01, Revision 2) until the Operating Permit can be administratively amended. This cannot happen until the U.S. Environmental Protection Agency (EPA) has reviewed the changes. BPXA may operate under the remaining terms and conditions of Minor Permit AQ0181MSS04 upon issuance.

The Department is submitting Minor Permit AQ0181MSS04 to EPA for their review. Federal regulations allow EPA up to forty-five days for their review. If EPA does not reply within this time, then the request is deemed acceptable. Once EPA completes its review, then BPXA can operate the portable emergency generator and the portable air compressor without the hourly operational limit (even if the Department has not yet issued the actual Administrative Amendment).

Modeling Review Memorandum dated 12/12/08

(Inserted as a word document, formatting and page numbers may be different from original)

MEMORANDUM

State of Alaska

Department of Environmental Conservation
Division of Air Quality

TO:	File	DATE:	December 12, 2008
		FILE NO:	AQ0181MSS04
THRU:	Alan Schuler, P.E Environmental Engineer Air Permits Program	PHONE NO: FAX NO:	269-7577 269-7508
FROM:	Patrick Dunn Environment Engineer Associate Air Permits Program	SUBJECT:	Review of BPXA Endicott Ambient Air Assessment

This memorandum summarizes the Department's findings regarding the ambient assessments submitted by BP Exploration Alaska Inc (BPXA) for the Endicott Production Facility (Endicott) Drill Rig and Permit Hygiene Project. BPXA submitted this analysis in support of their November 2008 AQ0181MSS04 Minor Permit application. BPXA intends to operate a Doyon 14 drill rig (Doyon 14) and a Doyon 16 drill rig (Doyon 16) under several different scenarios at both the Main Production Island (MPI) and the Satellite Development Island (SDI). BPXA is also requesting to remove an hourly annual limit on two existing Endicott emission units.

BPXA's ambient air analysis adequately demonstrates that operating the drill rig emission units within the requested constraints will not cause or contribute to a violation of the Alaska Ambient Air Quality Standards (AAAQS) provided in 18 AAC 50.010, or the maximum allowable increases (increments) listed in 18 AAC 50.020.

BPXA has previously operated drill rigs at Endicott under Condition 7 of Operating Permit AQ0455TVP01. The Department has previously reviewed several ambient assessments submitted under Condition 7. The most relevant to today's memo are described in the February 8, 2007 memorandum, "Review of Endicott Increment Ambient Assessment" and the February 5, 2008 memorandum, "Review of Endicott SDI Increment Assessment." The Department has also reviewed the ambient assessment submitted by BPXA in support of their February 2008 application for Construction Permit AQ0181CPT06 (Liberty Project). This assessment is described in the August 26, 2008 memorandum, "Review of BP Liberty Modeling Ambient Air Assessment." Today's memorandum only describes aspects which have changed subsequent to the previous assessments or that otherwise warrant discussion.

BACKGROUND

BPXA submitted the ambient assessment as part of the original minor permit application. The Department discovered several errors in the original ambient assessment and requested BPXA resubmit their ambient assessment to correct the errors. BPXA submitted the revised ambient assessment on December 4, 2008. See below for more detailed information on the errors in the original application. The assessments were conducted on behalf of BPXA by Hoefler Consulting Group (HCG). BPXA did not submit a formal modeling protocol for this project.

BPXA's application triggers minor permit review under 18 AAC 50.508(6) and 18 AAC 50.502(c)(2)(A). Per 18 AAC 50.540(k)(3), applicants subject to 18 AAC 50.508(6) must include in their application the effects of revising permit terms and conditions. BPXA was required to submit an annual AAAQS and increment analysis for NO_2, SO_2 and PM-10 because BPXA is requesting to remove annual operating limits previously established to protect standards and increments. Per 18 AAC 50.540(c)(2)(B), applicants subject to 18 AAC 50.502(c)(2)(A) must provide an ambient AAAQS analysis for nitrogen dioxide (NO_2), sulfur dioxide (SO_2) and particulate matter with an aerodynamic diameter less than 10 microns (PM-10).

BPXA submitted both an annual and short term increment analysis (as applicable) for NO_2, SO_2 and PM-10 for all of the requested operating scenarios. Although the short term increment analyses were not required under the minor permit rules, the Department *could have* requested them under 18 AAC 50.201(b) due to past increment modeling concerns at Endicott. Therefore, BPXA's submittal of the short-term SO_2 and PM-10 increment assessments was appropriate. BPXA only submitted an AAAQS analysis for NO_2 for the requested scenario at MPI. The Department has determined that the previous modeling done for Endicott has shown that Endicott is increment limited. Therefore the Department accepted BPXA's increment analysis as an adequate surrogate that the AAAQS is protected for the SDI scenarios. However, ***future applications for Endicott classified under 50.502(c)(2)(A) must include an actual ambient AAAQS analysis for NO_2, SO_2 and PM-10.***

APPROACH

BPXA used computer analysis (modeling) to predict the NO_2, SO_2, and PM-10 air quality impacts. BPXA modeled the following scenarios:

1. Doyon 14 and Doyon 16 operating concurrently at MPI during February through April for a maximum of 75 days per drill rig.
2. Doyon 14 and Doyon 16 operating concurrently at SDI during February through April for a maximum of 75 days per drill rig.
3. Doyon 14 and Doyon 16 operating concurrently with the Liberty drill rig (Liberty) at SDI during February through March for a maximum of 45 days per drill rig (excluding Liberty).
4. Doyon 14 operating concurrently with Liberty at SDI during February through April for a maximum of 75 days (excluding Liberty).
5. Doyon 16 operating concurrently with Liberty at SDI during February through April for a maximum of 75 days (excluding Liberty).

The Department had previously reviewed Scenario 2 in the February 5, 2008 memo; therefore BPXA did not resubmit the modeling for Scenario 2 in the original application. To avoid replicating results already established, BPXA used the results of the modeling for the Liberty Project to simplify the modeling for the current project. The modeling for the Liberty Project demonstrated the following according to BPXA:

1. Because of the predominant wind patterns, no significant overlap of ambient impacts exists between the MPI emission units and the SDI emission units.
2. The offsite inventory of Greater Prudhoe Bay (GPB) does not significantly impact air quality at Endicott.

Based on these results BPXA only modeled MPI emission units with the drill rig(s) when assessing impacts at MPI and only modeled SDI emission units with the drill rig(s) when assessing impacts at SDI. BPXA also excluded any off-site inventory when assessing the AAAQS impact at MPI. See the Off-Site Impacts section below for further discussion.

Model Selection

There are a number of air dispersion models available to applicants and regulators. The U.S. Environmental Protection Agency (EPA) lists these models in their *Guideline on Air Quality Models* (Guideline). BPXA used EPA's *AERMOD Modeling System* (AERMOD) for the ambient analysis. AERMOD is an appropriate model for this analysis.

The AERMOD Modeling System consists of three components: AERMAP (which is used to process terrain data and develop elevations for the receptor grid), AERMET (which is used to process the meteorological data), and AERMOD (which is used to estimate the ambient concentrations). BPXA used version 06341 of AERMET and 07026 of AERMOD. These are the current versions. BPXA did not use AERMAP in its modeling, as the area surrounding Endicott is ocean and can therefore be treated as "flat terrain."

The use of AERMOD is consistent with the assessments reviewed in the February 5, 2008 memo and the August 26, 2008 memo and continues to be appropriate.

Meteorological Data

BPXA used the same meteorological data as previously approved in the February 5, 2008 memo and the August 26, 2008 memo. BPXA continued to use the high second-high (h2h) modeled concentrations for comparison to the short term standards and increments and the high first-high (h1h) modeled concentrations for comparison to the annual standards and increments. BPXA's approach continues to be appropriate.

Emission Unit Inventory

The Doyon 14 and Doyon 16 emission units were consistent with the modeled drill rig emission units used in the ambient assessment reviewed in the February 5, 2008 memo. The emission units at SDI and the emission units at MPI were consistent with the emission units reviewed in the Liberty Project with the exception of stack heights (See below).

The Department finds BPXA's approach acceptable except for the inconsistent stack heights.

Emission Rates and Stack Parameters

The assumed emission rates and stack parameters have significant roles in an ambient demonstration. Therefore, the Department checks these parameters very carefully.

<u>Seasonal Operation</u>

BPXA used the EMISFACT keyword in the AERMOD model to simulate the seasonal operation of the different scenarios. BPXA inappropriately used the same factors for the short-term assessments as used in the annual assessments. Since the EMISFACT value is used to prorate the emission rate, they should have used a value of one (i.e., no adjustment) for each month that the emission unit will operate. BPXA incorrectly used the EMISFACT keyword in the short term assessments for Scenarios 3 through 5 in the original application. The Department also discovered that BPXA incorrectly used the EMISFACT keyword in their previously reviewed submittal for Scenario 2, therefore the Department requested BPXA resubmit the short term assessments for Scenarios 2 through 5 with the correct use of the EMISFACT keyword. BPXA corrected the use of the EMISFACT keyword for the short term assessments with their subsequent submittal.

SO_2 Emissions
SO_2 emissions are directly related to the amount of sulfur in the fuel. BPXA modeled the drill rig emission units (engines, boilers and heaters) using a fuel sulfur content of 0.10 weight percent sulfur (wt%S) in the original application submittal. In the subsequent submittal BPXA used Ultra-Low Sulfur Diesel fuel with a maximum sulfur content of 15 parts per million by weight (ppmw) sulfur in the drill rig engines with the exception of Scenario 2. The drill rig engines continued to be modeled with a fuel sulfur content of 0.10 wt%S for Scenario 2. While two levels of fuel sulfur content were used in the modeling analysis, the Department will require the lower fuel sulfur content as a permit condition for all drill rig emission units.

All of the diesel-fired units at the Endicott Facility may be required to use Ultra-Low Sulfur Diesel fuel in accordance with the Intermittently Use Oilfield Support Equipment policy as a result of the Liberty Project.

Operating Assumptions
BPXA assumed the Doyon 14 and Doyon 16 emission units operated at their maximum emission rates for the duration of the operation as defined in Scenarios 1 through 5. The SDI and MPI emission units were modeled under the same assumptions as was done for the Liberty PSD project.

BPXA requested that the existing annual hourly operating limits on the emergency generator and air compressor be removed as part of the current minor permit application. BPXA modeled these units without any hourly operational limit for both the current application and the Liberty Project; therefore the Department agrees with BPXA that these limits can be removed.

Stack Heights
Stack height can be a critical component of an ambient demonstration, especially when an emission unit is subject to downwash. Appropriate stack heights and base elevations were included as part of the modeling analysis.

BPXA had inconsistent stack heights in the original submittal. Several stack heights for emission units at the Liberty project were taller than what was submitted for the Liberty Project. There were also a few emission units whose stack heights were not consistent among the modeled pollutants. The Department asked BPXA to resubmit the assessment with consistent stack heights among pollutants and consistent stack heights among the current application and the Liberty project.

The Department found with BPXA's subsequent submittal that there were still several emission units with stack heights taller for the current application compared to the Liberty Project. BPXA told the Department that the taller stack heights were the design stack heights; therefore the Department will include the taller stack heights as a permit condition.

Ambient NO_2 Modeling

The modeling of ambient NO_2 concentrations can sometimes be refined through the use of ambient air data or assumptions. BPXA used the *Plume Volume Molar Ratio Method* (PVMRM) to refine the estimated ambient NO_2 concentrations associated with Endicott. They assumed full conversion for the off-site sources. The use of PVMRM for the Endicott emission units is appropriate, but warrants discussion. The use of full conversion for the off-site sources is consistent with past practice and remains acceptable.

<u>EPA and Department Approval</u>
Since PVMRM is a non-Guideline method under both State and Federal rule, permission must be obtained from both entities per 18 AAC 50.215(c)(3). The Air Permits Program Manager[4] gave approval on November 26, 2008 and EPA Region 10 approved BPXA's use of PVMRM for the Endicott project on November 24, 2008.

<u>Public Comment</u>
The use of a non-Guideline model is subject to public comment. Therefore, the Department is seeking public comment regarding the use of PVMRM in the public notice for the preliminary permit decision.

<u>In-Stack NO_2-to- NO_X Ratio</u>
The NO_X emissions created during combustion is partly nitric oxide (NO) and partly NO_2. EPA's long-standing practice is to assume that 90 percent (by volume) of the in-stack emissions is NO, and 10 percent is NO_2. After the combustion gas exits the stack, additional NO_2 is created as the exhaust mixes with atmospheric ozone.

Applicants may either use this default 10 percent NO_2-to-NO_X in-stack ratio, or assign alternative in-stack NO_2/NO_X ratios. BPXA used the default assumption for engines, heaters, and boilers, and used a ratio of 0.3 for the turbine, as was previously used for the Liberty project. The use of these NO_2-to-NO_X in-stack ratios remains appropriate.

<u>Ozone Data</u>
PVMRM is essentially an improved version of the *Ozone Limiting Method* (OLM), which is a Guideline NO_2 modeling method. Both methods require ambient ozone data in order to determine how much of the NO is converted to NO_2.

BPXA used the same ozone data that was used for the Liberty project, BPXA's approach remains acceptable.

<u>NO_2 Increment Modeling</u>
The use of PVMRM requires special care when modeling the NO_2 increment. Due to the ozone limiting feature of the algorithm, the NO_X emissions that occur during different time periods must be modeled separately.

BPXA was able to demonstrate compliance with the NO_2 increment without subtracting the baseline NO_2 concentration. This approach is conservative and precluded the need for making separate baseline runs. This is consistent with the approach used for the Liberty Project.

Ambient Air Boundary

For purposes of air quality modeling, "ambient air" means outside air to which the public has access. Ambient air typically excludes that portion of the atmosphere within a stationary

[4]The Commissioner delegated his authority regarding the use of non-guideline models to the Air Permits Program Manager on June 3, 2008

source's boundary. However, there may be exceptions if there are portions of the property that are used for off-duty housing.

BPXA continued to use the pad edge as the ambient air boundary for Endicott. BPXA's approach continues to be acceptable.

Receptor Grid

BPXA used the same receptor grid as used in the Liberty PSD project. The modeled receptor grids included receptors surrounding both the MPI and SDI pads. This included receptor spacing of 25 m around the boundary of each island, with receptor spacing of 50 m to a distance of approximately 500m, and receptors spaced at 200 m to a distance of approximately 3 km.

This grid was found to be acceptable for the Liberty PSD project and the Department finds it acceptable for the current project.

Downwash

Downwash refers to conditions where nearby structures influence plume dispersion. BPXA used the same downwash parameters used previously for the drill rigs and the same downwash parameters as used for the Liberty Project for the other emission units.

Background Concentrations

BPXA did not include any background concentration for the AAAQS analysis, therefore the Department added in the background concentration used for the Liberty Project.

Off-Site Impacts

As previously discussed, BPXA assumed off-site impacts do not have a significant impact at Endicott. Therefore, BPXA did not include off-site impacts in their analysis. The Department agrees that past modeling assessments have shown this to be the case in regards to off-site SO_2 and PM-10 impacts (AAAQS and increment). However, the Department initially questioned this approach in regards to the off-site NO_2 increment impact since the February 8, 2007 memorandum indicated that the cumulative off-site NO_2 increment impact from sources located within greater Prudhoe Bay was 1.1 micrograms per cubic meter ($\mu g/m^3$). This exceeds the significant impact level (SIL) of 1.0 $\mu g/m^3$, albeit only by a slight margin. The Department noted however, that this assessment was conducted with AERMOD's predecessor, ISCST3. The Department therefore reviewed BPXA's off-site NO_2 increment analysis submitted in August 2008 for the Liberty Project, since that analysis was conducted with AERMOD. In this case, the maximum NO_2 impact (0.98 $\mu g/m^3$) is slightly less than the 1.0 SIL. Therefore, the Department concurs with BPXA's statement that the off-site sources do not affect the NO_2 increment at Endicott.

The Department also reviewed the off-site NO_2 AAAQS impact at Endicott submitted with the Liberty Project and found that it is *not* below the SIL. Therefore, the Department added in the maximum NO_2 offsite impact from the Liberty Project (8.9 $\mu g/m^3$). The Department used a conservative approach of adding the maximum on-site and off-site impacts, regardless of whether or not the impacts were coincident in location or meteorological data year.

RESULTS AND DISCUSSION

The maximum NO_2 AAAQS impacts for Scenario 1 is shown in Table 1. The background concentration, off-site impact, total impacts and ambient standard are also shown. The total impact is less than the applicable AAAQS. Therefore, BPXA has demonstrated compliance with the NO_2AAAQS while operating under Scenario 1.

Table 1 – Scenario 1 Maximum AAAQS Impact

Air Pollutant	Avg. Period	Maximum Modeled Conc ($\mu g/m^3$)	Bkgd Conc ($\mu g/m^3$)	Off-site Conc ($\mu g/m^3$)	TOTAL IMPACT: Max conc plus bkgd ($\mu g/m^3$)	Ambient Standard ($\mu g/m^3$)
NO_2	Annual	54.3	11.3	8.9	**74.5**	100

The maximum NO_2, SO_2 and PM-10 increment impacts for Scenario 1, Scenario 2, Scenario 3, Scenario 4, and Scenario 5 are shown in Table 2, Table 3, Table 4, Table 5, and Table 6, respectively. The Class II increment standards are also shown. All of the maximum impacts for every scenario are less than the applicable Class II standards. Therefore, BPXA has demonstrated compliance with the Class II increment standards while operating under Scenarios 1 through 5.

Table 2– Scenario 1 Maximum Increment Impacts

Air Pollutant	Avg. Period	Maximum Modeled Conc. ($\mu g/m^3$)	Class II Increment Standard ($\mu g/m^3$)
NO_2	Annual	**24.5**	25
SO_2	3-hr	**230.9**	512
	24-hr	**80.8**	91
	Annual	**19.9**	20
PM-10	24-hr	**26.6**	30
	Annual	**5.5**	17

Table 3– Scenario 2 Maximum Increment Impacts[a]

Air Pollutant	Avg. Period	Maximum Modeled Conc. ($\mu g/m^3$)	Class II Increment Standard ($\mu g/m^3$)
NO_2	Annual	**24.9**	25
SO_2	3-hr	**138.7**	512
	24-hr	**88.1**	91
	Annual	**4.8**	20
PM-10	24-hr	**17.1**	30
	Annual	**1.4**	17

Table Notes:
[a] - The annual results are from the assessment reviewed in the February 5, 2008 memo.

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Table 4– Scenario 3 Maximum Increment Impacts

Air Pollutant	Avg. Period	Maximum Modeled Conc. (µg/m³)	Class II Increment Standard (µg/m³)
NO_2	Annual	**24.2**	25
SO_2	3-hr	**119.3**	512
	24-hr	**66.7**	91
	Annual	**12.2**	20
PM-10	24-hr	**20.8**	30
	Annual	**1.9**	17

Table 5– Scenario 4 Maximum Increment Impacts

Air Pollutant	Avg. Period	Maximum Modeled Conc. (µg/m³)	Class II Increment Standard (µg/m³)
NO_2	Annual	**24.3**	25
SO_2	3-hr	**108.5**	512
	24-hr	**62.5**	91
	Annual	**12.2**	20
PM-10	24-hr	**11.3**	30
	Annual	**1.9**	17

Table 6– Scenario 5 Maximum Increment Impacts

Air Pollutant	Avg. Period	Maximum Modeled Conc. (µg/m³)	Class II Increment Standard (µg/m³)
NO_2	Annual	**24.2**	25
SO_2	3-hr	**116.5**	512
	24-hr	**63.1**	91
	Annual	**12.1**	20
PM-10	24-hr	**12.6**	30
	Annual	**1.9**	17

It is important to note that since ambient concentrations vary with distance from each emission unit, the maximum values shown represent the highest value that may occur within the airshed. They do *not* represent the highest concentration that could occur at *each* location in the area.

CONCLUSION

The Department reviewed BPXA's modeling analysis for Endicott and concluded the following:

1. The NO_2, SO_2 and PM-10 emissions associated with operating the stationary source within the requested operating limits will not cause or contribute to a violation of the AAAQS listed in 18 AAC 50.010 or the increments listed in 18 AAC 50.020.
2. BPXA's modeling analysis fully complies with the showing requirements of 18 AAC 50.540(k)(3) and 18 AAC 50.540(c)(2)(B).
3. BPXA conducted their modeling analysis in a manner consistent with EPA's *Guideline on Air Quality Models*.

The Department has developed new conditions in the air quality control minor permit to ensure compliance with the ambient air quality standards and increments. These conditions are summarized below:

1. The drill rigs must only be operated seasonally as defined in the five scenarios,
2. The maximum fuel sulfur content may not exceed 15 ppmw in the drill rig emission units,
3. Maintain the minimum required stack heights of the Liberty emission units shown in Table 7, and
4. Remove the annual hourly operating limit on the portable emergency generator and the air compressor.

Table 7 Minimum Required Stack Heights

<table>
<tr><th>Emission Unit</th><th>Emission Unit Number in Table 1, Permit AQ0181CPT06</th><th>Minimum Required Stack Height (meters)</th></tr>
<tr><td>auxiliary generator</td><td>57</td><td rowspan="4">19.8</td></tr>
<tr><td>fire water pump</td><td>59</td></tr>
<tr><td>boilers</td><td>61 and 62</td></tr>
<tr><td>MAC heater</td><td>64</td></tr>
<tr><td>MAC Heater Pipe Barn 1</td><td>65</td><td rowspan="2">13.7</td></tr>
<tr><td>MAC Heater Pipe Barn 2</td><td>66</td></tr>
<tr><td>Bulk Mud boiler</td><td>63</td><td>12.2</td></tr>
</table>

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR PERMITS PROGRAM

TECHNICAL ANALYSIS REPORT

Air Quality Control Minor Permit AQ0166CPT04
BP Exploration (Alaska) Inc.
Central Compressor Plant (CCP)
H_2S LIMIT INCREASE PROJECT

AND

Air Quality Control Construction Permit AQ0270CPT04
BP Exploration (Alaska) Inc.
Central Gas Facility (CGF)
H_2S LIMIT INCREASE PROJECT

Prepared by Zeena Siddeek
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Final – October 13, 2009

TABLE OF CONTENTS

1.0 Introduction....4
1.1 Stationary Source Description....4
1.2 Permit History for CCP....4
1.3 Permit History for CGF....6
2.0 Application Description....7
2.1 Application for CCP....7
2.2 Application for CGF....7
2.3 Department Review of the Application....8
3.0 Emissions Summary....9
3.1 SO_2 Emissions at CCP....9
3.2 SO_2 Emissions at CGF....10
3.3 PSD Applicability....11
3.4 Assessable Emissions....12
4.0 Department Findings....13
5.0 Permit Requirements for a Permit classified under 18 AAC 50.306....16
5.1 General Requirements for PSD Permits....16
5.2 Best Available Control Technology (BACT) under 40 CFR 52.21(j)....18
5.3 State Emission Standards....19
5.4 Ambient Air Quality Standards....19
5.5 Requirement for all Air Quality Control Permits....20
6.0 Permit Administration....20
Exhibit A: Limits from Past Permit Actions and New Limits....22
Exhibit B: Modeling Memorandum....25
Exhibit C: BACT Review....

ABBREVIATIONS/ACRONYMS

AAAQS .... Alaska Ambient Air Quality Standard
AAC .... Alaska Administrative Code
ADEC .... Alaska Department of Environmental Conservation
AS .... Alaska Statutes
BACT .... Best Available Control Technology
BPXA .... BP Exploration (Alaska) Inc.
CCP .... Central Compressor Plant
CGF .... Central Gas Facility
CFR. .... Code of Federal Regulations
EPA .... Environmental Protection Agency
GHX .... Gas Handling Expansion
MIX .... Miscible Injection Expansion
NA .... Not Applicable
O/C .... Operating/Construction
ORL .... Owner Requested Limit
PSD .... Prevention of Significant Deterioration
PTE .... Potential to Emit
SIC .... Standard Industrial Classification
TAR .... Technical Analysis Report

Units and Measures

gr./dscf .... grains per dry standard cubic foot (1 pound = 7,000 grains)
dscf .... dry standard cubic foot
gph .... gallons per hour
kW .... kiloWatts[1]
lbs .... pounds
mmBtu .... million British Thermal Units
ppm .... parts per million
ppmv .... parts per million by volume
tpy .... tons per year
wt% .... weight percent

Pollutants

CO .... Carbon Monoxide
H_2S .... Hydrogen Sulfide
NO_X .... Oxides of Nitrogen
NO_2 .... Nitrogen Dioxide
NO .... Nitric Oxide
PM-10 .... Particulate Matter with an aerodynamic diameter less than 10 microns
SO_2 .... Sulfur Dioxide
VOC .... Volatile Organic Compound

[1] kW refers to rated generator electrical output rather than engine output

1.0 Introduction

This Technical Analysis Report (TAR) provides the Alaska Department of Environmental Conservation's (Department's) bases for issuing to BP Exploration (Alaska) Inc. (BPXA) Air Quality Control Construction Permit AQ0166CPT04 for the Central Compressor Plant (CCP), and Construction Permit AQ0270CPT04 for the Central Gas Facility (CGF).

The application is dated September 19, 2008, and the Department received it on October 2, 2008. BPXA submitted additional information on January 23, and May 22, 2009 for Best Available Control Technology (BACT) analysis.

In the Construction Permit AQ0270CPT04 for CGF, the Department is increasing the sulfur dioxide (SO_2) BACT limits (in the form of fuel gas H_2S limits) from 30 parts per million by volume (ppmv) to 300 ppmv for certain equipment that had a 30 ppmv BACT limit. The Department is also establishing ambient air protection limits for liquid fuel sulfur content and fuel gas H_2S content in Construction Permits AQ0166CPT04 and AQ0270CPT04 for CCP and CGF, along with stack restrictions on select emission units at CGF, to protect the SO_2 ambient air quality standards and increments.

Additionally, the Department is re-establishing the Title I permit conditions in Construction Permits AQ0166CPT04 and AQ0270CPT04, for the past permit actions and rescinding the past Title 1 permits for CCP and CGF.

1.1 Stationary Source Description

The CCP and CGF are considered as one stationary source for air permitting purposes. The aggregated CCP/CGF stationary source is classified as a Prevention of Significant Deterioration (PSD) major source for having the potential to emit greater than 250 tons per year (tpy) of one or more regulated pollutants.

The CCP receives part of the raw gas separated from crude oil in the BPXA flow stations and gathering centers. The raw gas flows through the two CCP inlet separators and then to the CGF, where separation takes place to produce a lean residue gas. This lean residue gas then flows back to the CCP where 17 compressors driven by 15 turbines compress the gas for injection into the gas cap of the Prudhoe Bay reservoir[2]. The CGF consists of 11 compressors, 3 oil heaters, 3 emergency generators, a firewater pump and 5 flares.

The fuel gas burned in the gas-fired emission units at CCP and CGF, originates at the Prudhoe Bay field. Because of fuel gas souring over time in the Prudhoe Bay gas reservoir, the H_2S in the fuel gas burned at the CGF has increased to near the permitted level of 30 ppmv listed in O/C Permit 270TVP01.

1.2 Permit History for CCP

The CCP was originally permitted prior to implementation of the PSD permitting program in 1977. Subsequent modifications to the CCP were permitted, prior to the Department obtaining the authority for the PSD permit program, by the Environmental Protection Agency (EPA). EPA issued four field-wide PSD permits (referenced in order as PSD I, PSD II, PSD III, and PSD IV) between May 1979 and September 1981 for new equipment operated at that time by Atlantic

[2] As described in Facility Identification in Statement of Basis, (page 2), of O/C Permit No. 166TVP01.

Richfield Company (ARCO) and Sohio Petroleum Company at the Prudhoe Bay Unit (PBU)[3]. EPA permitted modifications to CCP under the PSD I permit on May 17, 1979, the PSD II permit on June 13, 1980 and the PSD North Slope Swap Project on February 5, 1981. Each of the four EPA PSD permits for Prudhoe Bay was amended by EPA and reissued with clarifications and revised emission limits on August 29, 1997. The only EPA PSD BACT limits that apply at CCP are identified in the August 29, 1997 amendment to the PSD II permit. These limits, which apply to one CCP turbine only (unit tag no. NGT-18-1813), affect emissions of NO_X, CO and PM. No EPA PSD limits apply at CCP for SO_2 emissions.

On September 17, 1990, the Department issued a PSD permit for the Gas Handling Expansion (GHX I) Project (Permit No. 8936-AA006). [4]

A brief description of CCP permits in which the Department or EPA established limits is presented below, in order of issue date.

PSD-X80-09 revised August 29, 1997- This EPA permit was issued on September 29, 1981and was amended August 29, 1997. This permit contains BACT limits for Unit 13 of: NO_X: 150 ppmv @ 15% O_2, CO: 50 lb/MMscf, Particulate Matter (PM): 0.014 lb/MMBtu, and opacity: 10 percent (as surrogate for PM). As revised through 1997, the permit only contains the PM limit and the opacity limits.

Permit 8936-AA006 (GHX I Project) issued September 17, 1990 - This permit allowed the installation and operation of three new gas-fired turbines (only two turbines, Units 14 and 15) were installed), one new process heater (Unit 16), and thirteen upgraded turbines (Units 1 through 13) at the Central Compressor Plant. In this permit, the Department established NO_X and CO BACT limits for these units, as shown in Exhibit A). This permit action did not trigger PSD for SO_2. However, the permit did include a fuel gas H_2S limit of 30 ppmv, which was later removed by the Department in 2003 (in O/C Permit 166TVP01). The reason to include the 30 ppmv in 1990 was not documented in the TAR, but the Department suspects the limit was to avoid PSD for SO_2. The reason to remove the limit in 2003 was not documented in the Statement of Basis for Permit 166TVP01 either.

Permit 9573-AA014 issued January 19, 1996 - This permit was a renewal for Permit to Operate 8936-AA006. The Department carried over the BACT limits from 8936-AC006 to Permit to Operate No. 9573-AA014.

Construction Permit No. 0073-AC006 issued in 2000 and revised in July 2001 – The Department issued this permit to upgrade turbine Unit 2 with Lean Head End (LHE) technology and to install a new emergency generator Unit 23. This project avoided PSD review for NO_X and CO through Owner Requested Limits (ORLs). Because the Department included the provisions of this permit - after 'permit hygiene' - in Operating/Construction (O/C) Permit No. 166TVP01, it appears that Permit 0073-AC006 was replaced by O/C Permit 166TVP01 although not documented anywhere.

Operating/Construction Permit No. 166TVP01 issued August 4, 2003 - This O/C Permit contains the Title 1 provisions of Permits PSD-X80-09, 9573-AA014 and 0073-AC006. In the permit, the Department

[3] The permitted sources at PBU are now operated by BPXA

[4] Permit to Operate No. 8936-AA006 was renewed as Permit to Operate No. 9573-AA014 on January 19, 1996.

(1) revised the CO limit for Unit 16 (originally established in Permit 8936-AA0006) to 0.061 lb/MMBtu to reflect the 1996 version of AP-42 emissions factor for low-NO_X burner technology;
(2) removed the 150 ppmv BACT limit for Unit 2, ostensibly for what is referred to as 'permit hygiene' (the removal of this limit was a mistake as described in section 4.0 of this TAR);
(3) removed the 30 ppmv fuel gas H_2S limit for all units (at BPXA's request - see letter dated November 19, 1997) (according to BPXA, the limit was not necessary because fuel gas souring was not considered a modification at the time before the Department adopted the Federal PSD program); and
(4) included the EPA annual limits of 958 tpy of NO_X and 90 tpy of CO from EPA Permit PSD-X80-09. (This was part of EPA approval to transfer the EPA short-term BACT limits of 150 ppmv NO_X and 50 lb/MMscf CO for Unit 13. These are now Title I limits for Unit 13 in a Department issued permit. As a result of this there are no BACT limits for NO_X and CO for Unit 13 in the EPA permit.)

Permit 166TVP01 expired on September 3, 2008 along with the Title 1 provisions in it. BPXA is operating under the expired operating permit through a permit shield after submitting a timely permit renewal.

1.3 Permit History for CGF

The EPA initially authorized operations at CGF in 1984 under the permitting action known as SWAP IV, as an administrative revision to PSD permits for the Prudhoe Bay Unit (PBU) facilities. Under SWAP IV, the EPA authorized additional heater and turbine capacity at the location where the CGF was later constructed. The CGF was subject to PSD review and permitting by EPA, thereby ensuring that CGF process operations were constructed in accordance with EPA PSD rules.

The Department issued two PSD permits for CGF: for the Gas Handling Expansion (GHX II) project in 1993 and the Miscible Injection Expansion (MIX) project in 1998.

A brief description of CGF permits in which the Department or EPA established limits is presented below, in order of issue date.

PSD-X81-13 revised August 29, 1997- This EPA permit was issued on September 29, 1981and was amended August 29, 1997. This permit contains the following BACT limitsr:

Units 5 through 8 of: NO_X 150 ppmv and 999 tpy, CO: 0.17 lb/MMBtu and 193 tpy, SO_2 6.5 tpy, PM: 16 tpy and opacity: 10 percent (as surrogate for PM);

Units 9 and 10 of: NO_X 150 ppmv and 1,115 tpy, CO: 0.17 lb/MMBtu and 269 tpy, SO_2: 9.0 tpy, PM: 22 and opacity: 10 percent (as surrogate for PM); and

Units 12 through 14 of: NO_X 0.08 lb/MMBtu and 84 tpy, CO: 0.061 lb/MMBtu and 64 tpy, SO_2: 5.4 tpy and PM: 12 tpy.

Permit 9273-AA016 (GHX II Project) revised in December 23, 1996 – This permit was originally issued on May 11, 1993. The permit allowed the installation and operation of turbine Units 1 through 4, one emergency generator Unit 15 and installation of a waste heat recovery system on two existing turbine Units 9 and 10. The Department established NO_X, CO and PM

BACT limits for these units as shown in Exhibit A. Permit 9273-AA016 did not include an SO_2 or fuel gas H_2S limit.

Permit 9873-AC006 (MIX Project) issued July 15, 1998 - This permit allowed the installation of turbine Unit 11 and modifications to Units 1 through 4, 9 and 10. Units 9, 10 and 11 were fitted with Lean Head End (LHE) technology. The Department established NO_X, CO and SO_2 BACT limits for these units. The NO_X and CO BACT limits in this permit, superseded the BACT limits established in Permit 9273-AA016. The Department included the provisions of this permit – after 'permit hygiene' - in O/C Permit 270TVP01. O/C Permit 270TVP01 replaced Permit 9873-AC006 although not explicitly documented anywhere.

Operating/Construction (O/C) Permit 270TVP01 issued August 4, 2003 - This O/C Permit contains the Title 1 provisions of Permits PSD-X81-13, 9273-AA016 and 9873-AC006. Permit 270TVP01 expired on September 3, 2008 along with the Title 1 provisions in it. In the permit, the Department established an ORL of 30 ppmv (annual average) for fuel gas H_2S for turbine Units 5 through 8, and heater Units 12 through 14. The limit was requested by BPXA to reflect the EPA tpy SO_2 BACT limits for these units.

2.0 Application Description

2.1 Application for CCP

BPXA requested a minor permit under 18 AAC 50.508(5) to establish a liquid fuel sulfur content limit of 0.11 percent by weight in all the liquid fuel fired emission units (Units 23 through 25) to protect the 24-hour SO_2 ambient air quality increment near CCP and CGF. BPXA stated that no fuel gas H_2S limit is needed to protect the SO_2 AAAQS. BPXA also stated that no liquid fuel sulfur limits or fuel gas H_2S content limits exist for CCP.

The Departments findings regarding the application are in Section 4.0.

2.2 Application for CGF

The fuel gas H_2S content in the Prudhoe Bay gas reservoir has gradually increased over time. The level is now in the range of the 30 ppmv SO_2 BACT limit established at CGF for Emission Units 1 through 4 and 9 through 11. BPXA's permit application requested that the Department increase the fuel gas H_2S BACT limits in the O/C Permit 270TVP01.

BPXA's permit application requested the Department to make the following changes to the O/C Permit 270TVP01:

- Revise the fuel gas H_2S limit (SO_2 BACT) limit of 30 ppmv (not to exceed) to 300 ppmv (not to exceed) for the turbine Units 1 through 4 and 9 through 11.
- Rescind the fuel gas H_2S ORL of 30 ppmv (annual average) for the turbine Units 5 through 8 and 12 through 14. (Department Note: This annual average limit for Units 5 through 8 and 12 through 14 originated in O/C Permit 270TVP01 at BPXA's request[5], to reflect the SO_2 ton per year limits in the EPA permit PSD-X81-13).
- Establish limits to protect ambient air quality standards and increments for SO_2 as follows:

[5] As described in the Statement of Basis for Permit 270TVP01. The EPA annual limit is in the EPA permit.

- 105 ppmv (annual average) fuel gas H_2S ambient air protection limits for all fuel gas fired Units 1 through 14 and 19 through 23;
- 0.11 percent by weight sulfur content ambient air protection limit for liquid fired Units 15 through 18; and
- vertical, uncapped exhaust stack when any of the emergency generators combust liquid fuel with a sulfur concentration that exceeds 0.019 percent by weight.

- Process the application for CGF under 18 AAC 50.508(6) for a minor permit, to revise terms and conditions of an existing Title 1 permit. BPXA also submitted all the necessary information to process the application under 18 AAC 50.306. BPXA submitted a minor permit application because BPXA asserts that fuel gas souring is not, in itself a change in the method of operation, and therefore, is not a modification.

The Department's review of the application is in Section 2.3 and the findings regarding the application are in Section 4.0.

2.3 Department Review of the Application

The stationary source consisting of CCP and CGF is a PSD major stationary source because the existing PTE exceeds 250 tpy for one or more regulated pollutants.

BPXA has requested that Department increase the BACT limit only for those units at CGF that already have a BACT limit of 30 ppmv. The Department believes BPXA's request is based on EPA's 1987 Ogden Martin[6] guidance memorandum for correcting a BACT limit with which a source is not able to comply. The Department has used this guidance when an initial BACT limit was set too stringent for a source to comply despite the source taking all reasonable measures to attempt to comply. The Department has not found any EPA determination that this approach should be used for the situation where a source complied with a limit for years, but now requires either physical or operational controls to continue to comply with the limit because of fuel gas souring.

The requested change would increase authorized SO_2 emissions by 704[7] tons per year, and the applicant has in the past and is currently complying with the existing BACT limit. Therefore, the Department does not consider this change to be correcting a BACT limit. Consistent with the Department's decision on January 11, 2008 to the Endicott permit and EPA, Region 10's (R10'October 27, 2003[8] letter to ConocoPhillips Alaska Inc., the Department treats this change as a change in the method of operation of the emission units, but has agreed to follow any subsequent federal guidance on this point. Because the change in the method of operation results in a significant increase in actual emissions, the change is a major modification as defined in 18 AAC 50.990(53).

[6] November 1987 memorandum from EPA to Ogden Martin Tulsa municipal Waste Incinerator Facility: Request for Determination on BACT Issues

[7] Using current actual (based on 30 ppmv) to future potential (based on 300 ppmv) for only those units (Units 1 through 4 and 9 through 11) that have a current fuel gas H_2S BACT limit of 30 ppmv (See Table 2 of this TAR and Table 3 of Exhibit C of this TAR).

[8] October 2003, Memorandum from Janice Hastings, Acting Director, Office of Air Quality, EPA Region 10, to Thomas Manson, ConocoPhillips Alaska Inc. regarding SO_2 BACT determination for Kuparuk Seawater Treatment Plant.

EPA, R10's October 27, 2003 letter to ConocoPhillips Alaska Inc states that increasing H_2S concentration in field gas resulting from ConocoPhillips' practice of injecting seawater into the reservoir (to enhance crude oil recovery), is arguably a physical change. However, based on 40 CFR 51.166(b)(2)(iii)(e), BACT does not apply for emission units for which the use of higher sulfur fuel gas could be accommodated without violating any federally enforceable permit condition.

The turbines and heaters at CCP can accommodate the higher sulfur fuel gas without violating any federally enforceable permit conditions. Therefore, the increase in SO_2 emissions at CCP from burning fuel gas with higher H_2S content is not a change in the method of operation. Therefore, BACT is not required for the CCP emission units.

Similarly, turbine Units 5 through 8 and heater Units 12 through 14, at CGF can accommodate the higher fuel H_2S. Although these units have annual SO_2 limits, through EPA imposed BACT limits, they are not limited to burning higher sulfur fuel. With the higher sulfur fuel, they can still comply with the annual limit. Therefore, the increase in SO_2 emissions from burning high H_2S fuel is not a change in the method of operation for these units. Therefore, BACT is not required for these units, as a result of this project.

The 105 ppmv limit established in the permits for CCP and CGF (See Exhibit B of this TAR) are federally enforceable limits established under regulations approved pursuant to 40 CFR Subpart I. Therefore, any future relaxation of this limit for Units 5 through 8 and 12 through 14 at CGF or for units at CCP to accommodate a higher sulfur fuel would not qualify for the alternate fuel exemption.

3.0 Emissions Summary

3.1 SO_2 Emissions at CCP

Sulfur dioxide is the only pollutant affected by Permit AQ0166CPT04. There are no changes to emissions for any other pollutants. The SO_2 emissions before and after the modification are shown in Table 1. BPXA provided the calculations in the application.

The new potential to emit (PTE) shown in, Table 1 is based on fuel oil sulfur content of 0.11 percent by weight and fuel gas H_2S content of 105 ppmv (limit imposed by the Department to protect the ambient air quality standards and increments, in the vicinity of CCP (See Exhibit B, Modeling Memorandum). The 1997 Actual Emissions and current PTE (before Permit AQ0166CPT04) shown in Table 1 are based on fuel gas H_2S content of 30 ppmv and fuel oil sulfur content of 0.5 percent by weight although no limit existed for fuel oil prior to this permit. The current PTE shown in Table 1 is only for informational purposes.

Table 1 – SO_2 Emissions Before and After Modification by Permit No. AQ0166CPT04

ID	Unit Description	Rating	SO_2 (tpy)		
			2007 Actual Emissions[c]	**Current PTE**	**New PTE**[d]
1	GE MS5371 PATP Gas Compressor	35,400 hp ISO	7.11	9.1	32.0
2	GE MS5371 PATP w/LHE Gas Compressor	35,800 hp ISO	7.43	9.4	33.2
3	GE MS5371PATP Gas Compressor	35,400 hp ISO	6.86	9.1	32.0
4			6.84	9.1	32.0
5			7.06	9.1	32.0
6			7.11	9.1	32.0
7			6.40	9.1	32.0
8			6.05	9.1	32.0
9			7.16	9.1	32.0
10			6.77	9.1	32.0
11			6.96	9.1	32.0
12			7.15	9.1	32.0
13			7.04	9.1	32.0
14	GE MS5382C Tandem Compressor	38,000 hp ISO	7.17	9.8	34.4
15			7.02	9.8	34.4
16	Broach Glycol Heaters	28.5 MMBtu/hr	0.28	0.72	2.6
17		37.5 MMBtu/hr	0.13	0.95	3.4
18			0.07	0.95	3.4
19	Eclipse Glycol Heaters	10.7 MMBtu/hr	0.24	0.27	0.96
20		12.3 MMBtu/hr	0.00	0.31	1.11
21	BS&B TEG Reboilers	4.1 MMBtu/hr	0.00	0.10	0.37
22			0.00	0.10	0.37
23	Solar T-4001 Emergency Generator	3,550 hp	0.08	2.2	0.48[a]
24	GM Emergency Generator	3,600 hp	0.05	1.29	0.28[a]
25	Cummins Emergency Fire Water Pump	255 hp	0.01	0.13	0.03[b]
26	John Zink HP/IP Emergency Flare	2.0 MMscf/day combined total (pilot/purge/assist)	0.81	1.8	6.5
27	John Zink STV Emergency Flare				
28	Line Emergency Backup Flare				
29	Line Emergency Backup Flare				
	Total Emissions		**106**	**147**	**505**

Table 1 Notes:

[a]Based on existing annual operating limit of 200 hours.

[b] Based on existing annual operating limit of 295 hours.

[c] BPXA's permit application provided only the 2007 emissions. Baseline Actual Emissions for PSD applicability are pollutant emissions representative of a 24 consecutive month average during a ten year period preceding the date on which the application was submitted. However, the Department did not request actual emissions for 2006 because doing so would not change the outcome of the PSD permit applicability assessment.

[d] The new PTE is based on 105 ppmv H_2S in the fuel gas and 0.11 percent sulfur by weight in the liquid fuel.

3.2 SO_2 Emissions at CGF

Sulfur dioxide is the only pollutant affected by Permit AQ0270CPT04. There are no changes to any other pollutants. BPXA provided the calculations for Table 2 in the application. The Department agrees with the calculations. Table 2 shows the SO_2 emissions increases due to the changes in fuel gas H_2S content and fuel oil sulfur content. The new PTE is based on the ambient air protection limits for fuel gas H_2S content of 105 ppmv, fuel oil sulfur content of 0.11 percent by weight and the SO_2 BACT limits for Units 5 through 10 and 12 through 14 in EPA permit PSD-X81-13. The Actual Emissions and current PTE (before Permit AQ0270CPT04) are based on fuel gas H_2S content of 30 ppmv and liquid fuel sulfur content of 0.5 percent by weight (although no liquid fuel sulfur limit existed for CGF before Permit AQ0270CPT04).

Table 2 – SO_2 Emissions Before and After Modification by Permit No. AQ0270CPT04

ID	Unit Description	Rating	SO_2 (tpy)		
			2007 Actual Emissions[c]	Current PTE	New PTE[d]
1	GE Frame 6 Injection Compressors	53,665 hp ISO	8.84	11.9	42.7
2			9.09	11.9	42.7
3			8.79	11.9	42.7
4			8.86	11.9	42.7
5	Cooper Rolls/RB211-24C Booster Compressors	33,300 hp ISO	4.88	6.5	6.5[b]
6			4.74	6.5	6.5[b]
7	Cooper Rolls/RB211-24C Miscible Injectant Compressors	33,300 hp ISO	4.64	6.5	6.5[b]
8			4.22	6.5	6.5[b]
9	GE MS5382C (Frame 5) Refrigerant Compressors	38,000 hp ISO	5.88	9.0	9.0[b]
10			6.02	9.0	9.0[b]
11	GE MS5382C (Frame 5) Booster Compressor	38,000 hp ISO	6.97	9.5	34.0
12	Chiyoda-John Zink Hot Oil Heaters	216 MMBtu/hr	2.14	5.4	5.4[b]
13			2.15	5.4	5.4[b]
14			1.73	5.4	5.4[b]
15	GM (RMD)/20-645F4B Emergency Electric Generators	2,865 kW	0.106	1.6	0.314[a]
16			0.091	1.6	0.314[a]
17			0.089	1.6	0.314[a]
18	Caterpillar/3406P Emergency Fire Water Pump	330 hp	0.007	0.03	0.0259[a]
19	IHI-John Zink Emergency Flares	3.0 MMscf/day combined total (pilot/purge/assist)	1.76	2.7	9.7
20					
21					
22					
23					
	Total Emissions		**81**	**125**	**276**

Table 2 Notes:

[a] Based on existing annual operating limit of 200 hours.

[b] Annual BACT limits in EPA Permit No. PSD-X81-13, as amended on 08/29/97.

[c] BPXA's permit application provided only the 2007 emissions. Baseline Actual Emissions for PSD applicability are pollutant emissions representative of a 24 consecutive month average during a ten year period preceding the date on which the application was submitted. However, the Department did not request actual emissions for 2006 because doing so would not change the outcome of the PSD permit applicability assessment.

[d] Except for emission units with an existing EPA BACT limit for SO_2, the new PTE is based on 105 ppmv H_2S in the fuel gas and 0.11 percent sulfur by weight in the liquid fuel.

3.3 PSD Applicability

As shown in Table 3, the SO_2 emissions from the requested modifications for CGF and the resulting increase at the stationary source (CCP and CGF and CGF combined) exceed the PSD major modification threshold of 40 tons per year listed in 40 CFR 52.21(b)(23)(i) for SO_2.

Table 3 – PSD Applicability Analysis for SO_2

	Combined
Past Actual	187
PTE	781
Increase	594
PSD Major Modification Threshold	40
PSD Major Modification	yes

3.4 Assessable Emissions

The assessable emissions for CCP are shown in Table 4. These values (except SO_2) are copied from the operating permit renewal application for CCP at BPXA's request. The Department is not establishing these values in this permit action. The Department is only establishing the SO_2 component of the assessable emissions in Permit AQ0166CPT04 based on the new PTE for CCP.

Table 4 – Assessable Emissions for CCP

UNIT	EMISSIONS IN TONS PER YEAR					
	NO_X	CO	PM-10	SO_2	VOC	Total
Assessable Emissions listed in O/C Permit AQ0166TVP02 (renewal application)	14,237	1,631	208	147	84	16,307
Increase due to Permit AQ0166CPT04	0	0	0	358	0	358
New Assessable Emissions	14,238	1,631	208	505	84	16,665

Similarly, the assessable emissions for CGF are shown in Table 5. These values (except SO_2) are copied from the operating permit renewal application for CGF at BPXA's request. The Department is not establishing these values in this permit action. The Department is only establishing the SO_2 component of the assessable emissions in Permit AQ0270CPT04 based on the new PTE for CGF.

Table 5 – Assessable Emissions for CGF

UNIT	EMISSIONS IN TONS PER YEAR					
	NO_X	CO	PM-10	SO_2	VOC	Total
Assessable Emissions listed in O/C Permit No. AQ0270TVP02 (renewal application)	10,968	1,787	305	125	90	13,275
Increase due to Permit AQ0270CPT04	0	0	0	151	0	151
Assessable Emissions	10,968	1,778	305	276	90	13,426

4.0 Department Findings

The Department finds that:

In regards to *both* CCP and CGF

1. The combined CCP and CGF stationary source is located in the North Slope Borough. The project is consistent with the Alaska Coastal Management Program (ACMP) through AS 46.40.040(b)(1). The Department did not notify the local district and resource agencies of the permit action to request additional ACMP review because the North Slope Borough Coastal District plan does not have an enforceable policy in effect at this time. The Department informed the Coastal District Coordinator of the proposed project and provided opportunity to comment on the preliminary permit during the public comment period. In addition, the resource agencies had the opportunity to comment on the preliminary permit during the public notice period.

2. BPXA used a fuel gas H_2S content of 105 ppmv in their modeling analysis to keep the SO_2 impacts from CCP and CGF below the SO_2 significant impact levels at all offsite source locations. This restriction of the CCP/CGF significant impact area is a major component of BPXA's ambient air demonstration. As such, a fuel gas H_2S limit of 105 ppmv (instantaneous) is included in the CCP and CGF permits for purposes of protecting the SO_2 AAAQS and increments

In regards to *just* CCP

3. BPXA does not need an application under 18 AAC 50.508(5) for SO_2 because the project is PSD for SO_2. BPXA needs a fuel oil sulfur limit of 0.11 percent to protect the SO_2 ambient air quality standard and increments.

4. There are no liquid fuel sulfur limits for CCP prior to Permit AQ0166CPT04, except to comply with the state emissions standard of 500 ppmv for sulfur compound emissions under 18 AAC 50.055(c).

5. BPXA stated in the application, that there is no existing restriction for fuel gas content. After reviewing the past Title 1 permit actions for CCP, the Department found that the CCP contained a fuel gas H_2S limit of 30 ppmv that originated in 1990 in Permit 8936-AA006 for the GHX I project. The project was PSD for NO_X and CO. ARCO (owner at the time) avoided PSD review for SO_2 by assuming that the fuel gas H_2S content was less than 25 ppmv that amounted to 28 tpy for the GHX I project. Permit No. 8936-AA006 imposed a 30 ppmv limit for H_2S, but the permit TAR did not explain the underlying basis for the limit. The Department believes that 30 ppmv limit was imposed by the Department to limit the increase in sulfur emissions to the PSD threshold of 40 tpy. The H_2S limit was carried over to permit to operate 9573-AA014 in 1995. However, the Department removed the limit in O/C Permit 166TVP01 at BPXA's request (November 19, 1997 letter from BPXA to the Department) after finding that the limit was unnecessary to avoid PSD based on the rules and policies in place at the time.

6. CCP and CGF is one stationary source for permitting purposes. The SO_2 increase associated with the changes requested at CGF alone is greater than the 40 tpy PSD major modification threshold. Therefore, the Department reviewed the application

under 18 AAC 50.306 for the stationary source consisting of CCP and CGF, combined. However, BACT does not apply to CCP units because these units are capable of accommodating the higher sulfur fuel and the change is not considered a change in the method of operation of the CCP units under 40 CFR 51.166(b)(2)(iii)(e).

7. O/C Permit 166TVP01 (issued in August 2003), contains the provisions of Permit 0073-AC006 (issued in July 2000) after 'permit hygiene'. Therefore, O/C Permit 166TVP01 ought to have replaced Permit 0073-AC006. Because the Title 1 provisions are embedded in the operating permit that expired in December 2008, there is a need to collect all the Title 1 provisions of the past actions. In this Construction Permit AQ0166CPT04, the Department is explicitly rescinding Permit 0073-AC006. There is no need to explicitly rescind O/C Permit 166TVP01 because the permit has already expired but BPXA is operating only under a permit shield.

8. EPA (permit PSD-X80-09 as amended on August 29, 1997) established tpy (long term) and lb/MMBtu (short-term) BACT limits for Unit 13. EPA agreed to drop the NO_X and CO limits because the Department established NO_X and CO BACT limits for Unit 13. However, per Statement of Basis for Permit 166TVP01, EPA required the Department to include the annual NO_X and CO limits for Unit 13, in the Department's permit[9]. As a result, there are no NO_X and CO limits for Unit 13 in the EPA Permit.

9. The Department included the EPA PM BACT limit for Unit 13 in the O/C Permit 166TVP01 at BPXA's request. There is no requirement for the Department to carry over the EPA PM BACT limit for Unit 13 into Permit AQ0166CPT04 and BPXA has not requested the inclusion.

10. The Department established NO_X and CO BACT limits for the turbines (Units 1 through 15) in Permit 8936-AA006 for the GHX I project in 1990. The Department removed the BACT limits for Unit 2 in O/C Permit 166TVP01 by mistake, because of the more stringent ORLs later established to avoid PSD review for the MIX project (Permit 0073-AC006) in July 2000. Since BACT limits never go away unless replaced by another BACT limit, Unit 2 must contain the original BACT limits of 150 ppmv for NO_X and 50 lb/MMBtu for CO that were established in Permit 8936-AA006.

11. The basis for the historical 200 hour annual limit for the emergency generators (Units 23 and 24), and the 295 hour limit for the firewater pump (Unit 25), are unclear. The limit appeared in Permit 9273-AA016 but the TAR for the permit did not include an explanation for the limit. The limit may have been to protect ambient standards and increments. For the current permit action, BPXA relied on these limits to demonstrate compliance with the ambient air quality standards and increments. Because there is no clear basis for the historical limit, this permit includes the limit in the section for Ambient Air Quality Protection to provide the basis.

[9] This information was obtained from the Statement of Basis in Permit 270TVP01. The Department did not have a copy of the permit application for Permit 270TVP01 in hand to verify EPA's request to include the annual limits for Unit 13 in the Department issued permit.

12. The provisions in Construction Permit AQ0166CPT04, do not contravene conditions in O/C Permit No. 166TVP01. Therefore, BPXA can operate under the provisions of Construction Permit AQ0166CPT04 when the permit is issued. Such operation does not qualify for the permit shield provided by AS 46.14.290 until the construction permit is incorporated into the applicable Title V operating permit.

In regards to *just* CGF

13. BPXA submitted a permit application under 18 AAC 50.508(6) requesting to increase the fuel gas H_2S BACT limit to 300 ppmv (from 30 ppmv) for turbine Units 1 through 4 and 9 through 11. The permit application also contained the necessary information to process the application under 18 AAC 50.306 and 40 C.F.R. 52.21. The Department is processing the application under 18 AAC 50.306.

14. Fuel gas H_2S content of 300 ppmv BACT limit is higher than the 105 ppmv limit required for ambient protection. Under the definition of BACT in 40 CFR 52.21(b)(12), the BACT limit must be at least as stringent as the applicable standards under 40 CFR parts 60 and 61 and no other threshold is specified in the BACT definition.

15. The previous (prior to Permit AQ0270CPT04) fuel gas H_2S **BACT limit of 30 ppmv** (not to exceed) for Units 1 through 4 and 9 through 11, in Condition 13 of O/C Permit 270TVP01 originated in Permit No. 9873-AA006 in 1998 for the MIX project. That project was a PSD major modification for NO_X, CO and SO_2.

16. The 30 ppmv (annual average) limit for Units 5 through 8 and 12 through 14 found in Table 2, Table 3 and Condition 13 of O/C Permit 270TVP01 is **not a BACT limit** and was not a federally enforceable limit established under regulations approved pursuant to 40 CFR Subpart I or 40 CFR 51.166. The limit is an ORL that was established as an operating permit condition in O/C Permit No. 270TVP01 to reflect the EPA ton per year BACT limit for SO_2. On BPXA's request, the Department is rescinding the 30 ppmv ORL for Units 5 through 8 and 12 through 14.

17. BPXA has requested to revise the fuel gas H_2S (surrogate for SO_2) BACT limit to 300 ppmv (from 30 ppmv) to only those units that have an existing (prior to Permit AQ0270CPT04) BACT limit of 30 ppmv. The requested revision is a PSD modification for the stationary source. As a result of this modification, BACT applies to Units 1 through 4 and 9 through 11. BACT does not apply to Units 5 through 8 and 12 through 14 because these units are capable of accommodating the higher sulfur fuel and the change is not considered a change in the method of operation under 40 CFR 51.166(b)(2)(iii)(e).

18. There are no liquid fuel sulfur limits (prior to Permit AQ0270CPT04) for CGF. The only sulfur compound emissions limit is to comply with the SO_2 emissions standards of 500 ppmv in 18 AAC 50.055(c). SO_2 actual emissions (as shown in Table 2) are based on 0.5 percent fuel oil sulfur content and actual operating hours of the units.

19. O/C Permit 270TVP01 contains Title 1 provisions carried forward from Construction Permit 9873-AC006. Permit 270TVP01 has expired, and these Title 1 provisions have also expired. The Department did not intend for Title 1 provisions to expire, and this result is an artifact of the combined nature of permit 270TVP01 and the

change in permitting rules adopted in 2004. Therefore, the Department has included the past Title 1 requirements in this Construction Permit AQ0270CPT04 and explicitly rescinded Permit 9873-AC006. There is no need to explicitly rescind O/C Permit 270TVP01 because the permit has already expired and BPXA is operating only under a permit shield.

20. The Department included the EPA BACT limits from PSD-X81-13 (amended on August 29, 1997) in the O/C Permit 270TVP01 as an applicable requirement. There is no requirement for the Department to include the EPA limits in Permit AQ0270CPT04. Units 5 through 10 and 12 through 14 have annual SO_2 BACT limits in the EPA PSD-X81-13 permit. PTE calculations for SO_2 for this permit action included the annual limits in the EPA permit.

21. The basis for the historical 200 hour annual limit for the emergency generator Units 16 through 18 is unclear. The limit appeared in Permit 9273-AA016 but the TAR did not include an explanation for the limit. The limit may have been to protect ambient standards and increments. For generator Unit 15 (installed under Permit 9273-AA016 in 1993), the 200 hour limit is a BACT limit. For the current permit action, BPXA relied on these limits to demonstrate compliance with the ambient air quality standards and increments. The limit was included in the section for Ambient Air Quality Protection to clarify the basis for these conditions.

22. Increasing fuel gas H_2S would contravene the Title V permit condition for fuel gas H_2S of 30 ppmv. The construction permit revises the applicable requirement basis for this condition, but cannot change the condition for purposes of title V. This change at CGF does not qualify for the operational flexibility provisions of 40 CFR 71.6(a)(13), because it is a modification under Title 1 of the Clean Air Act. Therefore, the change requires a Title V permit revision before BPXA can operate under the provisions of Permit AQ0270CPT04.

5.0 Permit Requirements for a Permit classified under 18 AAC 50.306

These permits for CCP and CGF fulfill the requirements of 18 AAC 50.306 for PSD Permits. This TAR includes general requirements for PSD permits in Section 5.1.

5.1 General Requirements for PSD Permits

State regulations in 18 AAC 50.306 describe the elements that the Department must include in PSD permits. As described in 18 AAC 50.306(b), the owner or operator must comply with the requirements under 40 CFR 52.21 as adopted by reference in 18 AAC 50.040. As required under 40 CFR 52.21, this TAR includes:

1. A control technology review as required under 40 CFR 52.21(j), as adopted by 18 AAC 50.040(h)(8). The control technology review for this project is presented in Section 5.2 and details of the analysis are in Exhibit C of this TAR, and permit requirements incorporating the results of the control technology review are included in the permit.

2. A source impact analysis as required under 40 CFR 52.21(k), as adopted by 18 AAC 50.040(h)(9) to demonstrate that the project will not cause an air pollution violation.

A summary of the source impact analysis for this project is presented in Section 5.4 and the details are presented in Exhibit B, of this TAR. The permit requirements incorporating the results of the source impact analysis are included in Section 6 of Permits AQ0166CPT04 and AQ0270CPT04 for CCP and CGF, respectively.

3. An air quality analysis (preconstruction monitoring) as required under 40 CFR 52.21(m) as adopted by 18 AAC 50.040(h)(11). The air quality analysis for this project is presented in Exhibit B. There are no resultant permit conditions associated with this requirement.

4. A source description, as required under 40 CFR 52.21(n), as adopted by 18 AAC 50.040(h)(12). A description of this source and a list of emission units covered under CCP and CGF are presented in Sections 1.1, 3.1 and 3.2 of this TAR, and authorizations for construction of these units is included in Section 1 (Emission Unit Inventory) of the permit.

5. An analysis on the project's impact on visibility, soils, and vegetation as required under 40 CFR 52.21(o), as adopted by 18 AAC 50.040(h)(13). The impact analysis review for this project is presented in Exhibit B. There are no resultant permit conditions associated with this requirement.

6. The requirements for state emissions standards as required under 40 CFR 52.21(r)(3), as adopted by 18 AAC 50.040(h)(15) are in Section 3 of Permits AQ0166CPT04 and AQ0270CPT04.

In addition, 18 AAC 50.306(d) describe the elements that the Department must include in PSD permits. Therefore, this includes:

1. Terms and conditions necessary to ensure that the Permittee constructs and operates the proposed modification with appropriate monitoring equipment, testing requirements, recordkeeping, and reporting requirements. These include monitoring fuel gas H_2S limits and fuel oil sulfur content, operating hours of the emergency generators and the exhaust stack orientation at CGF. All other conditions are Title 1 requirements for past actions.

   Monitoring for fuel gas H_2S and fuel oil sulfur are the same as for compliance with state emissions standards for sulfur compound emissions and New Source Performance Standards Subpart GG that are already in place in the operating permits. Monthly monitoring for fuel gas is sufficient for compliance because fuel gas H_2S content variation is a very slow process. For fuel gas H_2S monitoring, the permits require testing using the standard test methods and reporting monthly. For fuel oil sulfur reporting, the permits require submitting monthly fuel sulfur analysis from either of the North Slope topping plants. i.e. the Prudhoe Bay or Kuparuk topping plants or submitting a list of the fuel grades received from a third-party supplier and the amount of fuel received for each shipment. Reporting stack orientation for the emergency generators at CGF is included in construction Permit AQ0270CPT04. Monitoring for the diesel generators are already in place in the operating permits. All other monitoring, recordkeeping and reporting requirements are for past actions and are copied from the operating permits for CCP and CGF. These provisions are included throughout each of the permits.

Note that the references to Permit 166TVP01 in Construction Permit AQ0166CPT04 and the references to Permit No. 270TVP01 in Construction Permit AQ0270CPT04, refer to the language in the respective operating permits and the language still applies even though these permits expired (on September 3, 2008). The Department's objective is to ensure that the requirements cross-referenced by conditions in other permits go on even if the other permit is rescinded, expired, or renewed.

2. Terms and conditions necessary to ensure the Permittee pay fees pursuant to 18 AAC 50.400-420. These requirements are included in Section 2.

5.2 Best Available Control Technology (BACT) under 40 CFR 52.21(j)

As described in 40 CFR 52.21(j) a major modification must apply BACT for each pollutant where the modification results in a significant net emissions increase at the source. As shown in Table 3, there is a significant emissions increase for SO_2, due to the requested increase in fuel gas H_2S content from 30 ppmv to 300 ppmv for Units 1 through 4 and 9 through 11 at CGF. BACT applies to each of these emission units at which a net increase will occur as a result of a physical or change in the method of operation of an emission unit. Therefore, each of these units is subject to BACT for SO_2.

BPXA evaluated the cost effectiveness of SO_2 control technologies that are feasible for emissions units that burn fuel gas and the financial impact to BPXA. The Department contracted Eastern Research Group (ERG) Inc., of 1600 Perimeter Park, Morrisville, NC 27560-8421 to review BPXA's BACT analysis. ERG reviewed and revised BPXA's cost estimates based on what ERG believed was appropriate. ERG's report is included as Exhibit C of this TAR after the Department made corrections and necessary contextual changes.

A summary of the Technically Feasible Control Technologies and the associated costs in order of control efficiency, are shown in Table 6 below. In the original application, BPXA claimed that H_2S Scavenging (Sulfa-Treat®) was technically infeasible because the fuel gas volume at CGF is too large for direct treatment. BPXA narrowed down only Liquid Redox (LO-CAT®) and the Adsorption Process (Amine) as technically feasible. ERG did not agree with BPXA's analysis. After requesting for additional information, on May 22, 2009, BPXA submitted the cost analysis to demonstrate that Sulfa-Treat® was cost ineffective.

BPXA's BACT analysis (October 2008), was based on treating 136 MMscf/d, of fuel gas burned in the turbines and heaters at CGF only. When the Department contracted ERG to review BPXA's BACT analysis, it was thought that BACT applied to all the units that burned high sulfur fuel gas. Therefore, the Department revised BPXA's cost estimates to include all of the units that burn fuel gas at the stationary source that included the units at CCP and CGF. However, after careful examination of the alternate fuels exemptions allowed under 40 CFR 51.166(b)(2)(iii)(e), the Department has concluded that BACT applies only to Units 1 through 4 and 9 through 11 at CGF. The Department did not re-visit BACT cost analysis because there is no benefit to doing so. The cost estimates based on treating a larger volume of fuel gas (to include fuel gas burned in all the equipment at CCP and CGF) is more conservative than the cost estimates based on the fuel gas burned only in Units 1 through 4 and 9 through 11 at CGF. Moreover, any change to the cost estimate will not alter the final BACT conclusions.

ERG based the BACT analysis (see Table 3 of Exhibit C), based on treating 295 MMscf/d (including the 5 MMscf/day from the flares), of fuel gas burned at CCP and CGF with H_2S

content of 300 ppmv. The projected SO_2 emissions, using fuel gas with 300 ppmv H_2S is 2,647 tpy. The combined CCP and CGF PTE based on the ambient air protection limit 105 ppmv for ambient protection, is 781 tpy (see Table 3). The cost effectiveness based on the 300 ppmv is more conservative than using the 105 ppmv.

Table 6 - Technically Feasible Control Technology

Control Technology	Annualized Costs (Revised)	Control Efficiency (%)	Cost $/ton removed	
			Applicant Estimate	Revised Estimate
Liquid Redox (LO-CAT®)	$ 38,201,145	99.7%	$ 15,526	$ 14,476
H_2S Scavenging (Sulfa-Treat®)	$ 33,461,456	98.7%	$ 13,420	$ 12,806
Adsorption Process (Amine)	$ 46,369,135	96.7%	$ 21,729	$ 18,113

Under 40 CFR 52.21(b)(12) the permitting agency is allowed to take into account the energy, environmental, or economic impacts and other costs on a case by case basis. The Department finds that even using a conservative baseline fuel gas H_2S content of 300 ppmv, the cost effectiveness of the control technologies listed in Table 6 are significantly higher than what the Department has previously determined as BACT for SO_2. Therefore, the Department agrees with BPXA that BACT for souring of the fuel gas is good combustion practices with no controls, based on the available fuel gas quality.

The Department has included fuel gas H_2S content limit of 300 ppmv as SO_2 BACT for turbine Units 1 through 4 and 9 through 11 at CGF.

5.3 State Emission Standards

As described in 40 CFR 52.21(r)(3), the source must comply with applicable Federal and State standards. No new Federal requirements are triggered by this modification. The only new requirement under the state implementation plan is for fuel burning equipment to comply with sulfur compound emissions standard of 500 ppmv under 18 AAC 50.055(c). Calculations have shown that as long as the fuel gas H_2S content is below 4,000 ppmv, the sulfur compound emissions will be less than 500 ppmv. Therefore, no additional monitoring requirements are necessary for compliance.

BPXA is not installing new emission units under these permits. Ongoing monitoring requirements are already in place in each of the operating permits for compliance with the state emissions standards. Therefore, there is no need to repeat the ongoing monitoring requirements in Construction Permit AQ0270CPT04 and AQ0166CPT04.

5.4 Ambient Air Quality Standards

BPXA submitted an ambient demonstration for SO_2 in order to satisfy the requirements of 40 CFR 52.21(k) and 18 AAC 50.040(h)(9). A memorandum describing the Department's review of the ambient demonstrations is in Exhibit B of this TAR.

5.4.1 Limit Necessary for CCP

BPXA's application requested a fuel oil sulfur content limit of 0.11 percent by weight for the oil fired equipment. The Department's review of BPXA's modeling analysis found that in order to satisfy BPXA's request to maintain air quality impacts to below significant impact levels in the vicinity of offsite sources, the following limits are necessary.

1. For all diesel-fired emission units, limit the maximum fuel sulfur content to 0.11 percent, by weight.
2. For all gas-fired emission units, limit the maximum H_2S content to 105 ppm (on an instantaneous basis).
3. Limit the annual operations for the emergency generators to 200 hours.
4. Limit the annual operations for the firewater pump to 295 hours.

5.4.2 Limit Necessary for CGF

BPXA's application requested a fuel gas H_2S limit of 105 ppm (annual average) for all the gas equipment and fuel oil sulfur content limit of 0.11 percent by weight. The Department's review of BPXA's modeling analysis found that in order to, the following limits are necessary

1. For all diesel-fired emission units, limit the maximum fuel sulfur content to 0.11 percent, by weight.
2. For all gas-fired emission units, limit the maximum H_2S content to 105 ppm (on an instantaneous basis).
3. Limit the annual operations for the emergency generators and firewater pump to 200 hours.
4. Construct and maintain vertical, uncapped exhaust stacks for the three emergency generators (Tag No. NGI-19-2802, NGI-19-2819, NGI-19-2890), except when the liquid fuel sulfur content at CGF is less than or equal to 0.019 percent, by weight. When the fuel sulfur content is less than or equal to 0.019 percent, the stacks may be capped or have a horizontal discharge. The uncapped stack requirement does not preclude the use of flapper valve rain covers, or other similar designs, that do not hinder the vertical momentum of the exhaust plume.

5.5 Requirement for all Air Quality Control Permits

The permit contains the requirements as necessary to ensure that the Permittee will construct and operate the stationary source in accordance with 18 AAC 50, as described in 18 AAC 50.345(c)(1) and (2) and (d) – (h). These requirements are listed in Section 7 of Construction permit AQ0166CPT04 and Section 6 of Construction Permit AQ0270CPT04 under "Standard Permit Conditions."

6.0 Permit Administration

BPXA is currently operating CCP and CGF under O/C Permits 166TVP01 and 270TVP01, respectively (expired but operating under a permit shield after applying for operating permit renewals).

For reasons described in Item 12 of the Department Findings Section 4.0, BPXA can operate CCP under the provisions of Construction Permit AQ0166CPT04 upon issuance. For reasons described in Item 22 of the Department Findings Section 4.0, BPXA must obtain a permit revision to the operating permit before operating CGF under the provisions of Construction Permit AQ0270CPT04.

The Department notes that permit renewals for the operating permits for CCP and CGF are underway at the same time as these Title 1 permits are processed. The Department will incorporate the provisions of AQ0166CPT04 and AQ0270CPT04 into the respective operating permits.

Exhibit A: Limits from Past Permit Actions and New Limits

Limits for Emissions Units at the Central Compressor Plant

Unit		8936-AA006 (PSD for NO_X and CO)	0073-AA006 Rev 1 (Avoided PSD)	166TVP01 (‘Permit hygiene’)	AQ0166CPT04 (PSD for SO_2)
1	NO_X	Est. BACT limit of 150 ppmv at 15% O_2			
	CO	Est. BACT limit of 50 lb/MMscf			
	PM				
	SO_2	see "all fuel gas units" below		see "all fuel gas units"	Est. 300 ppmvd BACT limit
2	NO_X	Est. BACT limit of 150 ppmv at 15% O_2	Est. PSD avoidance limit of 134 lb/hr, and 90 ppmvd at 15% O_2. No change to BACT limits.	Remove BACT limit of 150 ppmv @ 15% O_2	Re-establish BACT limit of 150 ppmv, 15% O_2
	CO	Est. BACT limit of 50 lb/MMscf	Est. 177 tpy PSD avoidance limit	Remove BACT limit of 50 lb/MMscf	Re-establish BACT limit of 50 lb/MMscf
	PM				
	SO_2	see "all fuel gas units" below		see "all fuel gas units"	Est. 300 ppmvd BACT limit
3 thru 12	NO_X	Est. BACT limit of 150 ppmv at 15% O_2			
	CO	Est. BACT limit of 50 lb/hr			
	PM				
	SO_2	see "all fuel gas units" below			Est. 300 ppmvd BACT limit
13	NO_X	Est. BACT limit of 150 ppmv at 15% O_2		Add 958 tpy (transfer from EPA Permit PSD-80-09)	
	CO	Est. BACT limit of 50 lb/MMscf		Add 90 tpy (transfer from EPA Permit PSD-80-09)	
	PM				
	SO_2	see "all fuel gas units" below		see "all fuel gas units"	Est. 300 ppmvd BACT limit
14 and 15	NO_X	Est. BACT limit of 150 ppmv at 15% O_2			
	CO	Est. BACT limit of 50 lb/MMscf			
	PM				
	SO_2	see "all fuel gas units" below			Est. 300 ppmvd BACT limit
16	NO_X	Est. BACT limit of 0.08 lb/MMBtu		No change to BACT limit	
	CO	Est .BACT limit of 0.018 lb/MMBtu		Revise BACT limit to 0.061 lb/MMBtu	
	PM				
	SO_2	see "all fuel gas units" below		see "all fuel gas units"	Est. 300 ppmvd BACT limit
All fuel gas units	SO_2	Est. 30 ppmv fuel gas H_2S limits (limit for all fuel gas units, presumably to avoid PSD for SO_2)		Remove 30 ppmv limit	

Limits for Emissions Units at the Central Gas Facility

Unit		9273-AA016 (PSD for NO_X, CO and PM)	9873-AC006 (PSD for NO_X, CO and SO_2)	166TVP01 (Permit hygiene)	AQ0166CPT04 (PSD for SO_2)
1 thru 4	NO_X CO PM SO_2	Est. BACT limit of 132 ppmv at 15% O_2 Est. BACT limit of 100 lb/MMscf Est. 14 lb/MMscf	Est. BACT limit of 125 ppmv at 15% O_2 and 282 lb/hr Est. BACT limit of 10 ppmv at full load No change to PM BACT limit Est. BACT limit of 30 ppmv fuel gas H_2S		Est. 300 ppmvd BACT limit
5 thru 8	NO_X CO PM SO_2			Est. ORL of 30 ppmv fuel gas H_2S	Est. 300 ppmvd BACT limit
9 and 10	NO_X CO PM SO_2	Est. BACT limit of 150 ppmv at 15% O_2 Est. BACT limit of 109 lb/MMscf No PM BACT limit established	Est. BACT limit of 85 ppmv at 15% O_2 and 130 lb/hr Est. BACT limit of 20 ppmv at full load Est. BACT limit of 30 ppmv fuel gas H_2S		Est. 300 ppmvd BACT limit
11	NO_X CO PM SO_2		Est. BACT limit of 85 ppmv at 15% O_2 and 130 lb/hr Est. BACT limit of 20 ppmv at full load Est. BACT limit of 30 ppmv fuel gas H_2S		Est. 300 ppmvd BACT limit
12 thru 14	NO_X CO PM SO_2			Est. ORL of 30 ppmv fuel gas H_2S	Est. 300 ppmvd BACT limit
15	NO_X CO PM SO_2	Est. BACT limit of 146.4 lb/hr Est. BACT limit of 2.8 lb/hr Est. BACT limi 1.0 g/hp-hr Est. BACT limit of 200 hour/year		Est. ORL of 30 ppmv fuel gas H_2S	Est. 300 ppmvd BACT limit
All fuel gas units	SO_2				Est. 300 ppmvd BACT limit for Units 1 through 4 and 9 through 11.

Exhibit B: Modeling Memorandum

MEMORANDUM

State of Alaska
Department of Environmental Conservation
Division of Air Quality

TO:	File	DATE:	September xx, 2009
THRU:		FILE NO:	AQ0270CPT04 – Modeling AQ0166CPT04 – Modeling
		PHONE:	465-5100
		FAX:	465-5129
FROM:	Alan E. Schuler, P.E. Environmental Engineer Air Permits Program	SUBJECT:	Review of BPXA's Ambient SO_2 Assessment for CGF/CCP -- **REVISED**

This memorandum summarizes the Department's *revised* findings regarding the ambient sulfur dioxide (SO_2) assessment submitted by BP Exploration (Alaska), Inc. (BPXA) for the Central Gas Facility (CGF) and the Central Compressor Plant (CCP).[1] BPXA submitted this analysis in support of their September 2008 Prevention of Significant Deterioration (PSD) permit application for CGF, and their September 2008 minor permit application for CCP.[2] BPXA's ambient air analysis adequately demonstrates that operating the CGF and the CCP emission units within the constraints described in this memorandum will not cause or contribute to a violation of the SO_2 Alaska Ambient Air Quality Standards (AAAQS) provided in 18 AAC 50.010, or the SO_2 maximum allowable increases (increments) listed in 18 AAC 50.020.

The Department also finds that BPXA's PSD applications adequately complies with the source impact analysis required under 40 CFR 52.21(k), the pre-construction monitoring analysis required under 40 CFR 52.21(m)(1), and the additional impact analysis required under 40 CFR 52.21(o).

BACKGROUND

CGF and CCP are existing, adjacent facilities located within the Prudhoe Bay Unit (PBU) of Alaska's North Slope. They are considered as a single stationary source, but operate under a different set of Title I and Title V air quality control permits.

Due to their close proximity and classification as a single stationary source, BPXA modeled both facilities together. This memorandum likewise treats the analysis as a combined assessment, even though the analysis was submitted in support of two different permit applications.

[1] This revision supersedes the February 23, 2009 version of the Department's memorandum regarding BPXA's ambient SO_2 assessment for CGF and CCP. The Department revised the memorandum to address issues raised by BPXA during the public comment period for the assoicated permit actions.
[2] The Department subsequently determined that BPXA's permit application for CCP was subject to PSD review.

Area Classification

The North Slope is unclassified in regards to compliance with the AAAQS. For purposes of increment compliance, CGF/CCP is located within a Class II area of the Northern Alaska Intrastate Air Quality Control Region. The nearest Class I area, Denali National Park, is located approximately 750 kilometers (km) to the south of CGF/CCP.

Source/Project Description

CGF and CCP are classified as a PSD-major stationary source. BPXA is presently operating CGF under Operating Permit AQ0270TVP01, and CCP under Operating Permit AQ0166TVP01.

BPXA submitted the permit applications to accommodate an expected increase in the hydrogen sulfide (H_2S) content of their fuel gas. The H_2S content at CGF is currently restricted to 30 parts per million by volume (ppmv) due to a Best Available Control Technology (BACT) limit imposed during a previous PSD review. BPXA would like to increase the BACT limit to 300 ppmv. Both limits are on a not-to-exceed (i.e., instantaneous) basis.

There are no existing H_2S restrictions to protect the SO_2 AAAQS/ increments. However, BPXA is requesting an *annual average* H_2S limit of 105 ppmv, and various other limits at both CGF and CCP, in order to protect the SO_2 AAAQS/increments. All of BPXA's proposed ambient air related limits are listed below:

<u>BPXA's Proposed Ambient Air Limits for **CCP**</u>

- Liquid fuel sulfur limit of 0.11 percent, by weight

<u>BPXA's Proposed Ambient Air Limits for **CGF**</u>

- Liquid fuel sulfur limit of 0.11 percent, by weight
- Fuel gas H_2S limit of 105 ppmv (annual average)
- Vertical, uncapped stacks for the three GM (EMD) emergency generators (Emission Units 15 – 17), whenever the sulfur content of the liquid fuel burned by these units exceeds 0.019 percent, by weight

The numerical value of BPXA's proposed H_2S limit for ambient air protection is less than the proposed BACT limit. BPXA provided a detailed clarification regarding the basis for these differences in a December 17, 2008 electronic mail (e-mail) message.[3]The Department's findings regarding the proposed ambient air limits are provided in this memorandum.

Ambient Demonstration Requirements

An increase in the fuel gas H_2S level will lead to an increase in the SO_2 emissions. The SO_2 emissions associated with BPXA's requested revisions are sufficient to classify the project as a PSD-major modification. Per 18 AAC 50.306, PSD applicants must essentially comply with the federal PSD requirements in 40 CFR 52.21. The ambient requirements include:

- A "Source Impact Analysis" (aka an ambient AAAQS and increment analysis) for the PSD-triggered pollutants – per 40 CFR 52.21(k),

[3] E-Mail from Rachael Buckbee (BPXA) to Alan Schuler (ADEC) and Fathima Siddeek (ADEC); *FW: CGF H_2S Limit*; December 17, 2008.

- An "Air Quality Analysis" (aka preconstruction monitoring data) for the PSD-triggered pollutants – per 40 CFR 52.21(m);
- An "Additional Impact Analyses" – per 40 CFR 52.21(o); and
- A Class I impact analysis (for sources which *may* affect a Class I area) – per 40 CFR 52.21(p).

The nearest Class I area to CGF, Denali National Park, is 750 km away. This is too distant to warrant a Class I impact analysis under 40 CFR 52.21(p).

BPXA's request to limit the fuel sulfur content at CCP is classified as an owner requested limit under 18 AAC 50.508(5). This classification incurs no unique obligations in regards to ambient demonstrations.

Modeling Protocol

BPXA submitted a general modeling protocol in October 2001 for assessing the SO_2 impacts associated with fuel gas souring within PBU.[4] The Department approved the protocol, with comment, on April 18, 2002.

BPXA's consultant, ENSR Corporation (which is now known as AECOM Environment), verbally discussed the adequacy of the 2001 protocol with me on April 8, 2008.[5] ENSR summarized this conversation in an April 16, 2008 e-mail.[6] I provided additional comments on April 24, 2008.[7] BPXA described all changes from the protocol in Section 1.1 of their modeling report (Attachment VI of their application). The Department's findings regarding the resulting analysis are described in the applicable portions of this memorandum.

Project Submittal

BPXA submitted the application on September 22, 2008. ENSR prepared the actual permit applications, and conducted the ambient assessment, on behalf of BPXA.

AMBIENT AIR POLLUTANT DATA

40 CFR 52.21(m)(1) requires PSD applicants to submit ambient air monitoring data describing the air quality in the vicinity of the project, unless the existing concentration or the project impact is less than the monitoring threshold provided in 40 CFR 52.21(i)(5). The requirement only pertains to the pollutants subject to PSD review. If monitoring is required, the data are to be collected prior to construction. Hence, these data are referred to as "pre-construction monitoring" data. Ambient "background" data may also be needed to supplement the estimated ambient impact from the proposed project. BPXA's approach for meeting both data needs is discussed below.

[4] The protocol was prepared by BPXA's consultant at that time, SECOR International Incorporated.
[5] ENSR was represented by Thomas Damiana and Anthony Galligan.
[6] E-Mail from Thomas Damiana (ENSR) to Alan Schuler (ADEC); *CCP/CGF SO_2 Modeling Procedures for PSD Review*; April 16, 2008.
[7] E-Mail from Alan Schuler (ADEC) to Thomas Damiana (ENSR); *RE: CCP/CGF SO_2 Modeling Procedures for PSD Review*; April 24, 2008.

Pre-Construction Monitoring

BPXA noted that the project impacts exceed the SO_2 pre-construction monitoring threshold. Therefore, pre-construction SO_2 data is needed for this application.

The pre-construction monitoring data must be collected at a location and manner that is consistent with the U.S. Environmental Protection Agency's (EPA's) *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA-450/4-87-007), which is adopted by reference in 18 AAC 50.035(a)(5). In summary, the data must be collected at the location(s) of maximum impact, the data must be current, and the data must meet the PSD quality assurance requirements.

BPXA operates a long-term ambient nitrogen dioxide (NO_2), SO_2, ozone (O_3) and particulate matter (PM-10) monitoring station at CCP. The location adequately meets the pre-construction siting requirements for the CGF/CCP stationary source. BPXA used the latest SO_2 data available at the time of application (the 2007 data set) to meet the pre-construction monitoring requirement.

BPXA submitted the 2007 CCP data for Department review on May 2, 2008. The data was reviewed on behalf of the Department by Enviroplan Consulting (Enviroplan), who found that the SO_2 data adequately meets the PSD quality assurance requirements.[8]

BPXA did not reiterate the maximum SO_2 concentrations in their PSD application. The Department is therefore providing these values below in Table 1. The values are reported in both a volumetric basis (parts per million – ppm), which is the format used in BPXA's monitoring data report, and on a mass basis (micrograms per cubic meter – µg/m^3) which is the format used in modeling. The ambient standard (in both formats) is also provided. The maximum concentrations are well below the AAAQS.

Table 1: Maximum SO_2 Concentrations Measured at CCP During Calendar Year 2007

Air Pollutant	Avg. Period	Volumetric Basis (ppm)		Mass Basis (µg/m^3)		% of AAAQS
		Max Conc	AAAQS	Max Conc	AAAQS	
SO_2	3-hr	0.011	**0.5**	29	**1300**	2%
	24-hr	0.009	**0.14**	24	**365**	6%
	Annual	0.001	**0.031**	3	**80**	3%

Background Concentrations

In addition to the pre-construction monitoring requirements for PSD pollutants, ambient "background" data may also be needed to supplement the ambient impact analysis. The

[8] *Meteorological and Pollutant Data Review – BPXA 2007 Prudhoe Bay Unit Data*; Enviroplan Consulting; January 5, 2009.

background concentration represents impacts from sources not included in the modeling analysis. Typical examples include natural, area-wide, and long-range transport sources.

The background concentration must be evaluated on a case-by-case basis for each ambient analysis. Once the background concentration is determined, it is added to the modeled concentration to estimate the total ambient concentration. Hence, background concentrations are typically needed for all air pollutants included in an AAAQS compliance demonstration, regardless of whether or not PSD pre-construction monitoring is required.

BPXA used the maximum concentrations measured at their A Pad monitoring station during calendar year 2007 as the background concentrations. This is an appropriate data set for this application. The maximum values are provided in the "Results and Discussion" section of this memorandum.[9] The A Pad data was reviewed with the CCP data (by Enviroplan) and was also found to meet the PSD quality assurance requirements.

SOURCE IMPACT ANALYSIS

BPXA used computer analysis (modeling) to predict the ambient SO_2 air quality impacts. The Department's findings regarding BPXA's analysis are provided below.

Approach

BPXA made two sets of preliminary runs with just the CGF/CCP emission units in order to reduce the number of receptors needed for the subsequent cumulative (aka "full field") impact assessment. This approach is warranted (especially when modeling large emission inventories – as is the case here) in order to produce acceptable computer run times.

One set of runs was used to cull out "far-field" receptors with insignificant *project* impacts. For purposes of this analysis, BPXA considered receptors located between 2 and 8 km of CGF/CCP as far-field. BPXA defined the project impacts as the proposed change in *gas-fired* SO_2 emissions – i.e., the SO_2 emissions associated with a fuel gas H_2S content of 105 ppm minus the SO_2 emissions associated with the most recent two-year average fuel gas H_2S concentration (which is 25 ppm). BPXA did <u>not</u> include the *liquid-fired* units in the project impact analysis since their SO_2 emissions are decreasing. Excluding the liquid-fired units makes the project impact analysis conservative.

In the second set of preliminary runs, BPXA modeled the "near-field" receptor grid (receptors located within 2 km of CGF/CCP) to find the 30 worst-case near-field receptors. BPXA modeled the potential SO_2 emissions at CGF/CCP, rather than just the project emissions. BPXA selected 30 receptors, rather than 10 (as proposed in the 2001 modeling protocol), in response to the Department's April 24, 2008 comments questioning the adequacy of only 10 near-field receptors. The use of 30 worst-case receptors, compiled from all three SO_2 averaging periods and all five meteorological data years (see Meteorological Data discussion), makes the subsequent AAAQS/increment analysis adequately robust.

[9] BPXA reported the maximum concentrations measured at A Pad in Table 1-20 (of Attachment VI) of their application. BPXA reported the values in both ppm and $\mu g/m^3$. The Department found that the reported 3-hour and annual average ppm values contain typographical errors. However, the reported $\mu g/m^3$ values are correct.

BPXA included both the 30 worst-case near-field receptors and the significant far-field receptors in the full field AAAQS/increment analysis. They also modeled the following two scenarios:

- A fuel gas H_2S content of 105 ppm for the gas-fired CGF/CCP emission units, and a liquid fuel sulfur content of 0.11 percent (by weight) for the diesel-fired CGF/CCP emission units. However, in order to demonstrate compliance with the air quality standards and increments, BPXA noted that the horizontal exhaust stacks on the three CGF emergency generators (Tag Nos. NGI-19-2802, NGI-19-2819, and NGI-19-2890) must be turned vertical (with no rain caps).

- The same 105 ppm H_2S content, but with a liquid fuel sulfur content of 0.019 percent (by weight) and no stack modifications for the three CGF emergency generators.

<u>Intermittent Well Servicing Equipment</u>
BPXA included intermittent well servicing equipment in the full field analysis, as requested by the Department in the April 4, 2002 protocol approval. BPXA assumed well servicing activities are occurring at the West Gas Injection (WGI) pad, which is located 0.5 km north of CCP. This is the nearest pad to CCP/CGF on which well servicing activities might occur. BPXA used the Alpine Frac Unit source characterization to represent the well servicing activities. This is consistent with the Department's April 2002 recommendation.

<u>Increment Analysis</u>
The SO_2 baseline date for the Northern Alaska Intrastate Air Quality Control Region is June 1, 1979. Therefore, there are both baseline and increment consuming emission units within the PBU, including CGF and CCP.

BPXA's approach for modeling the SO_2 increment consumption is described in Section 1.2 of Attachment VI of their application. In summary, BPXA assumed the SO_2 emissions from all *gas-fired* CGF/CCP emission units are *entirely* increment consuming since the baseline H_2S level is unknown (i.e., they did not take any credit for the baseline SO_2 emissions). They likewise did <u>not</u> take credit for the increment *expanding* CGF/CCP emissions associated with the decrease in liquid fuel sulfur content. Both of these assumptions result in a larger SO_2 modeled increment impact than what will really occur. BPXA did <u>not</u> include offsite intermittent well servicing equipment in the increment analysis per the Department's *Intermittently Used Oilfield Support Equipment* policy (Policy and Procedure No. 04.02.105). BPXA's approach for modeling the SO_2 increment is reasonable and conservative.

Model Selection
There are a number of air dispersion models available to applicants and regulators. The U.S. Environmental Protection Agency (EPA) lists these models in their *Guideline on Air Quality Models* (Guideline), which the Department has adopted by reference in 18 AAC 50.040(f). BPXA used EPA's AERMOD Modeling System (AERMOD) for the ambient analysis. AERMOD is an appropriate model for this application.

The AERMOD Modeling System consists of three components: AERMAP (which is used to process terrain data), AERMET (which is used to process the meteorological data), and AERMOD (which is used to estimate the ambient concentrations).

BPXA only needed to use the AERMET and AERMOD components in the CGF/CCP analysis. BPXA did not need to use the AERMAP component since there are no significant terrain features near CGF/CCP or the greater PBU area. BPXA used the current version of each applicable component (version 07026 for AERMOD and version 06341 for AERMET).

BPXA recompiled the AERMOD source code using Intel's FORTRAN compiler. Prior to recompiling the code, BPXA corrected a FORMAT statement error regarding the placement of the page header form-feeds. BPXA made no other changes to the source code. According to the application, they also conducted test runs to confirm that the recompiled version provided the same results as EPA's compiled version.

Section 3.1.2 of the Guideline allows users to make minor changes to the source code, as long as the changes do not affect the resulting concentrations. Recompiling the source code and correcting print-out errors fall within this category of acceptable changes. To confirm that BPXA did not inadvertently introduce an error to the program, the Department made limited test runs using both BPXA's version and EPA's version. The Department confirmed that BPXA's version provides the same results as EPA's version.

Meteorological Data

AERMOD requires hourly meteorological data to estimate plume dispersion. According to the Guideline, a *minimum* of one-year of site-specific data, or five years of representative National Weather Service (NWS) data should be used. When modeling with site-specific data, the Guideline states that additional years (up to five) should be used when available to account for year-to-year variation in meteorological conditions.

BPXA used three years (1998, 1999 and 2006) of PBU A Pad surface data for this analysis. BPXA substituted missing solar radiation and temperature difference (SRDT) data with cloud cover data measured by the NWS at Deadhorse. They also used concurrent NWS upper air data from Barrow.

Discussion re Land-Sea Breeze Affects

BPXA noted that CGF/CCP is located 1 kilometer (km) inland, while the A Pad meteorological station is 12 km inland. They therefore addressed whether the A Pad data adequately represents the potential land-sea breezes that may exist at CGF/CCP, since the public has raised this type of question in other North Slope projects.

BPXA provided a number of arguments based on boundary layer theory and a 2007 study conducted by the U.S. Mineral Management Services (MMS) to support their position that the A Pad data is adequately representative of the CGF/CCP meteorological conditions. They also analyzed the meteorological conditions associated with the highest 24-hour SO_2 increment impact. They did not assess the meteorological conditions associated with the other SO_2 averaging periods, or the maximum AAAQS impacts, since the modeled impacts were much less than the applicable standard (i.e., there could be notable error in the analysis without jeopardizing the compliance demonstration).

BPXA found that the twenty highest 24-hour SO_2 increment impacts occur during mid to late winter. Land-sea breezes do not occur during this time due to little or no solar radiation and continuous snow/ice cover between the land and sea. BPXA further noted that the highest mid-winter impacts occur during periods of sustained high winds blowing parallel to the coast (i.e., opposite to land-sea breezes). The highest late-winter impacts occur during periods of strong surface inversions and low variable winds. Both events create conditions that would lead to worst-case impacts for the CGF/CCP emission units.

BPXA's argument regarding the mid-winter wind events is compelling. Gerry Guay of the Department's Monitoring and Quality Assurance Group also confirmed that North Slope winters tend to be windier than summers, after reviewing a 1920-1970 climatological data set from Barrow and a 1947-1970 climatological data set from Barter Island.[10]

The Department further notes that the maximum impacts from CGF/CCP occur at pad edge and are either associated with downwash conditions, or strong inversions (which are accommodated with low wind speeds). Land-sea breezes do not occur during inversions, so periods with inversions are not in question. Downwash occurs when there is sufficient wind speed to entrain the exhaust plume into the building wake. The cause for these higher wind speeds (i.e., whether it be sea-land induced or weather front induced) is irrelevant. The question is: are the wind speeds and directions that lead to the highest impacts adequately characterized? If this answer is unclear, then the next question becomes: would the correction of the alleged error in wind speed/direction change the conclusion of the compliance demonstration.

The Department agrees with BPXA's argument that most of the modeled scenarios have an adequately wide margin for error. The 24-hour increment analysis of the 0.019% fuel sulfur scenario is the one exception. In this case, the maximum impact is 95-percent of the Class II increment. The maximum impacts for all other scenarios are *no more than* 61-percent of the applicable standard. Most of the maximum impacts are no more than a third of the applicable standard. Therefore, the land-sea breeze question focuses on whether the winds at CGF/CCP would be sufficiently different from the winds at A Pad to lead to a modeled violation of the 24-hour increment. The potential for that kind of variation, or an unrepresented condition, is unlikely.

The Department therefore considers the A Pad surface data as site-specific for purposes of characterizing the meteorological conditions at CGF/CCP. The use of three years of data exceeds EPA's minimum data requirements and allows for the potential year-to-year variations in meteorology to be assessed.

[10] E-Mail from Gerry Guay (ADEC) to Alan Schuler (ADEC); *RE: Meteorological Data Question re North Slope Land-Sea Breezes*; December 23, 2008.

Quality Assurance Review Findings

The Department previously reviewed the 1998, 1999 and 2006 A Pad meteorological data to determine whether they meet the PSD criteria for acceptability. The Department's findings regarding the 1998 and 1999 meteorological data were transmitted to BPXA in a July 19, 2007 letter.[11] The findings regarding the 2006 meteorological data were transmitted to BPXA on February 14, 2008.[12] The findings for all three data years are summarized below:

1998-1999 A Pad Meteorological Data

- Out of a 1998-2000 and 2002 data set reviewed by the Department, 1999 is the only year that completely complies with the PSD quality assurance requirements.
- With one exception, all of the 1998 meteorological data meet the PSD criteria for acceptability. The wind speed data for the 4th quarter is the one exception due to inadequate data capture (85.5 percent instead of the required 90 percent).
- BPXA may nevertheless use the 1998 data in conjunction with the 1999 data since the data capture is still fairly good and the 1999 data satisfies the minimum meteorological data requirements.[13]

2006 A Pad Meteorological Data

- With one exception, all of the 2006 A Pad meteorological data meet the PSD criteria for acceptability. The delta-temperature parameter was the one exception due to inadequate data capture (76.1 percent instead of the required 90 percent).

While not stated in the findings for the 2006 data, the Department allowed BPXA to use the 2006 A Pad meteorological data since:

1) the 1999 data already satisfies the minimum data requirements;
2) most aspects of the 2006 data set also meet the PSD requirements; and
3) the Deadhorse NWS cloud-cover data is an acceptable surrogate for missing delta-temperature data.

AERMET Surface Parameters

AERMET requires the area surrounding the meteorological tower to be characterized in regards to the following three surface characteristics: noon-time albedo, bowen ratio, and surface roughness length. EPA has provided additional guidance regarding the selection and processing of these values in their *AERMOD Implementation Guide*.

BPXA used the same values as previously approved and used for A Pad. However, the use of these values warrants discussion due to EPA's January 2008 revision to the *AERMOD Implementation Guide*.

[11] July 19, 2007 letter from Alan Schuler to Jim Pfeifer (BPXA), "A Pad Data Review Findings and Request for Revised WRDx Modeling Protocol."

[12] E-mail from Alan Schuler to Jim Pfeiffer (BPXA) and Alison Cooke (BPXA); *2006 A-Pad/CCP Data Findings*; February 14, 2008.

[13] Section 8.3.1.2b of the Guideline allows the use of partial meteorological data years when combined with a complete year of data.

BPXA originally proposed the A Pad surface characteristics in the modeling protocol for their WRDx Gas Partial Processing PSD Project (as revised on December 28, 2006). The Department then listed the accepted values in the January 31, 2007 protocol approval. In EPA's subsequent revision to the *AERMOD Implementation Guide*, the domain and methodology for weighting the surface parameters changed. BPXA therefore reviewed the previous values to determine whether they needed to be revised for the CGF/CCP analysis. BPXA noted that the land cover around A Pad is fairly homogeneous throughout an area that extends beyond the area used to determine the AERMET surface characteristics. The resulting values would therefore be identical using either method. The Department agrees with BPXA's assessment and is continuing to accept the previously approved surface characteristics for A Pad. The accepted values are repeated below in Table 2.

Table 2: Approved AERMET Surface Parameters for A Pad

Surface Parameter	Winter Value	Summer Value
Albedo	0.8	0.18
Bowen Ratio	1.5	0.80
Surface Roughness Length	0.004	0.02

For purposes of the A Pad AERMET surface parameters, summer is defined as June through September, and winter is defined as October through May.

<u>Design Concentrations</u>
EPA allows applicants to compare the high second-high (h2h) modeled concentration to the short-term air quality standards if at least one year of temporally representative site-specific, or five years of representative NWS data, are used. When these criteria are not met, then applicants must use the high first-high (h1h) concentration. In all cases, applicants must compare the h1h modeled concentration to the annual average standards/increments, the SILs, and the pre-construction monitoring thresholds. The Department allowed BPXA to compare the h2h concentration to the short-term AAAQS/increments since they used site-specific meteorological data.

Emission Unit Inventory

BPXA modeled all of the gas-fired and liquid-fired emission units listed in the current Title V permits for CGF and CCP. The emission unit inventories are provided in Tables 1-1 and 1-2 of Attachment VI of BPXA's application.

Emission Rates and Stack Parameters

The assumed emission rates and stack parameters have significant roles in an ambient demonstration. Therefore, the Department checks these parameters very carefully.

<u>Operational Restrictions</u>
BPXA assumed most of the CGF/CCP emission units are constantly operating. The only exceptions regard the liquid-fired units, all of which have an existing annual operating limit. BPXA used these existing limits when modeling the annual average SO_2 impacts. The liquid-fired units, and their annual operating limits, are listed below in Table 3.

Table 3: Emission Units with Annual Operating Limits

Source/Emission Unit			Limit (hr/yr)
Model ID	Tag No.	Description	
CGF			
1110	NGI-19-2802	GM 20-645F4B Emergency Generator	200
1111	NGI-19-2819	GM 20-645F4B Emergency Generator	200
1121	NGI-19-2890	GM 20-645F4B Emergency Generator	200
1122	NGI-18-1529	Caterpillar/3406P Emergency Fire Water Pump	200
CCP			
816	EDTG-18-2897	Solar T-4001 Emergency Generator	200
817	EDG-18-2897-01	GM Emergency Generator	200
818	EDG-18-1522	Cummins Emergency Fire Water Pump	295

The historical purpose for the annual operating limits is not well documented. However, in reviewing the current analysis, it is apparent that the annual restrictions are needed to at least protect the annual average SO_2 AAAQS and increment. The Department suspects the annual limits are likewise needed to protect the annual average nitrogen dioxide (NO_2) AAAQS/increment and the annual average particulate matter (PM-10) AAAQS/increment. This is especially probable in regards to NO_2 since the NO_2 AAAQS/increment tend to be more restrictive than the SO_2 AAAQS/increment when modeling combustion units. The potential need for restricting the annual operations to protect the PM-10 AAAQS/increment is not as clear. However, if an annual restriction is needed to protect the annual SO_2 AAAQS/increment, then an annual restriction is *likely* needed to protect the annual PM-10 AAAQS/increment as well. The Department presumes that is the case here. The Department is therefore clarifying through this memorandum that the annual operating limits listed in Table 3 are being imposed to protect the annual average NO_2, SO_2 and PM-10 AAAQS/increments.[14]

SO_2 Emissions

SO_2 emissions are directly related to the amount of sulfur in the fuel. The sulfur in fuel gas is in the form of H_2S. The sulfur in liquid fuel (e.g., diesel) is in the form of elemental sulfur. While BPXA's requested H_2S and fuel sulfur limits have already been presented, BPXA's assumptions warrant additional discussion.

BPXA assumed the maximum liquid fuel sulfur content at CCP and CGF is 0.11 percent, by weight. This is a notable reduction from the current 0.75 percent threshold associated with the 500 ppm SO_2 emission limit listed in 18 AAC 50.055(c). The Department is therefore imposing BPXA's 0.11 percent fuel sulfur assumption as a permit limit at both CCP and CGF, in order to protect the SO_2 AAAQS/increments.

While BPXA assumed the *maximum* liquid fuel sulfur content is 0.11 percent, they also ran an alternative scenario where the fuel sulfur content *at CGF* is less than 0.019 percent (while the fuel sulfur content at CCP remains at 0.11 percent). In this case, BPXA used a lower fuel sulfur

[14] The Department's presumption does not preclude BPXA from submitting additional information (e.g., a revised air quality modeling analysis) under 18 AAC 50.508(6) to demonstrate that annual limits are not necessary to protect the annual AAAQS/increments.

content to offset the increased impacts from an alternative stack design. This scenario is further discussed in the Horizontal/Capped Stack section of this memorandum.

BPXA requested an *annual average* H_2S limit for CGF. They did not request any H_2S limits for CCP. The requested limit for CGF is 105 ppm. BPXA also stated that an instantaneous limit is *not* needed to protect the short-term AAAQS/increments since the H_2S content would need to increase to 250 ppm during the short-term period in order for the SO_2 increment to be consumed.

BPXA provided a brief supporting argument for an annual average limit in Section 1.11.3 of Attachment VI. They also provided additional clarification regarding their assertions, in response to Department questions.[15, 16] BPXA concluded, "Since the fuel gas H_2S levels at CGF and CCP vary less than 30 percent on a short-term basis and less than 10 percent on an annual basis, it is possible to conclude that compliance can be assured by monitoring fuel gas levels only once per year, at least as long as the measured concentration is considerably less than 250 ppmv."

The Department notes that BPXA derived the 250 ppm H_2S value from a post-run analysis of their *near-field* impacts. However, they did not evaluate the potential far-field effects.

BPXA limited their cumulative impact assessment to the project's significant impact area (SIA). BPXA assumed an instantaneous H_2S content of 105 ppm when establishing the SIA. Therefore, BPXA's argument regarding the 250 ppm upper bound is incomplete.

The Department conducted a cursory sensitivity test by rerunning the 24-hour SIA analysis for a randomly selected meteorological data year (2006). The Department found that at 250 ppm, the SIA would extend to Gathering Center 3 (GC3) and the Central Power Station (CPS). Since this area was not included in BPXA's cumulative impact assessment, it is unknown whether BPXA could still demonstrate compliance with the AAAQS/increments within this new area.

BPXA used 105 ppm, rather than 250 ppm, as the instantaneous H_2S content in their ambient analysis. The Department is therefore imposing 105 ppm as an *instantaneous* limit. The monitoring frequency can be the same as that imposed under the Best Available Control Technology (BACT) analysis.

The Department acknowledges that a higher instantaneous H_2S limit (somewhere between 105 ppm and 250 ppm) *may be* viable. However, BPXA would need to provide that demonstration in order for the Department to impose a higher fuel gas H_2S limit.

<u>Horizontal/Capped Stacks</u>
The presence of non-vertical stacks or stacks with rain caps requires special handling in an AERMOD analysis. Most of the emission units at CGF and CCP have vertical, uncapped releases. However, there are several units with horizontal releases (including the three CGF

[15] E-mail from Thomas Damiana (AECOM) to Alan Schuler (ADEC); *BPXA CCP/CGF H_2S Increase Application – Gas-fired source impact conclusions explanation*; January 28, 2009.
[16] E-mail from Sims Duggins (AECOM) to Alan Schuler (ADEC); *RE: BPXA CCP/CGF H_2S Increase Application – Gas-fired source impact conclusions explanation*; January 29, 2009.

emergency generators). There are also offsite emission units with either horizontal or capped releases.

The proper approach for characterizing a horizontal/capped stack is described in EPA's, *AERMOD Implementation Guide*. For capped and horizontal stacks subject to building downwash, the user should input the actual stack diameter and exit temperature, but set the exit velocity to a nominally low value (0.001 m/s). If the capped/horizontal stack is *not* subject to downwash, then the 0.001 m/s exit velocity should be used along with an artificially large diameter (set to maintain the actual exhaust flowrate). Minor adjustments to the stack height may also be warranted.

EPA has developed a non-default option in AERMOD that will revise the stack characteristics as warranted, for stacks that are identified as capped or horizontal. EPA Region 10 granted the Department permission to use this option in general in October 2007.[17] BPXA used this non-default option to characterize all capped/horizontal stacks.

BPXA requested that the Department impose a permit condition to require vertical stack orientations for the three CGF emergency generators whenever the sulfur content of the liquid fuel burned by these units exceeds 0.019 percent, by weight. The Department reviewed the files and agrees that a vertical stack orientation is required to protect the SO_2 AAAQS/increment whenever these units burn fuel with a sulfur content ranging between 0.019 percent and the fuel sulfur cap (0.11 percent). The Department is therefore including this condition in the CGF permit.

<u>Stack Dimensions</u>
BPXA stated that they made an extensive effort to verify and update the physical stack parameters for CGF and CCP. The Department compared computerized images of the modeled stack/building configurations to photographs of the CGF and CCP facilities. The modeled stack heights appear valid. The stack diameters and orientations likewise appear valid.[18]

Ambient Air Boundary

For purposes of air quality modeling, "ambient air" means outside air to which the public has access. Ambient air typically excludes that portion of the atmosphere within a stationary source's boundary. BPXA used the pad edge as the ambient air boundary. This is an appropriate ambient air boundary for North Slope sources.

Receptor Grid

BPXA used a 500 meter grid spacing in the far-field (i.e., 2 km – 8 km) significant impact analysis. BPXA also placed additional receptors near around Gathering Center 1 (GC-1), and the

[17] E-mail from Herman Wong (EPA R10) to Alan Schuler (ADEC); *RE: Capped/Horizontal Stack Issue*; October 2, 2007.

[18] The Department found an "error" in Table 1-10 of Attachment 6 in regards to the stack diameter listed for the CGF Emergency Fire Water Pump (unit NGI-19-1529). The stated 31.5 meter diameter is actually the artificially large diameter used to characterize horizontal stacks in a non-downwash scenario. However, according to the modeling files that BPXA provided, the actual diameter for this unit is 0.15 meters. Therefore, this is just a reporting error, not a modeling error.

Gathering Center 3 (GC-3) and Central Power Station (CPS) pads. This not only made the SIA analysis more robust, it also highlighted the approximate location of these sources.

BPXA stated that *only* the 24-hour averaging period had significant impacts within the far-field grid. The Department found a single exception: the 3-hour averaging period has a single receptor with significant impacts during the 2006 meteorological data year. However, this receptor also had significant 24-hour impacts, so the effect of this oversight is moot.

For the preliminary near-field analysis, BPXA used the following receptor grid density:

- 25-meter spacing along the ambient air boundary;
- 25-meter resolution from the boundary outward to 100 meters in each cardinal direction;
- 100-meter resolution from the 25-meter grid outward to 1 kilometer (km) in each direction; and
- 250-meter resolution from the 1km grid outward to 2 km in each direction.

In the full-field (cumulative impact) analysis, BPXA limited the receptor grid to the 30 worst-case near-field receptors and the far-field receptors that had significant project impacts.

BPXA's receptor grids are acceptable. The maximum cumulative impacts (for the given H_2S and fuel-sulfur assumptions) occur in the CGF/CCP near-field.

Downwash

Downwash refers to conditions where nearby structures influence plume dispersion. Downwash can occur when a stack height is less than a height derived by a procedure called "Good Engineering Practice," as defined in 18 AAC 50.990(42). The modeling of downwash-related impacts requires the inclusion of dimensions from nearby buildings.

EPA has established specific algorithms for determining which buildings must be included in the analysis and for determining the profile dimensions that would influence the plume from a given stack. EPA has incorporated these algorithms into the "Building Profile Input Program" (BPIP) computer program. BPXA used EPA's PRIME version of BPIP (BPIPPRM, version 04274) to determine the building profiles needed by AERMOD. This is an appropriate version of BPIP.

BPXA included building downwash for the CGF and CCP emission units, along with those offsite sources located near the CGF/CCP SIA (i.e., GC-1, GC-2, GC-3 and CPS). BPXA stated that they reviewed and revised, when warranted, the previously assumed CGF/CCP building parameters. The Department compared the assumed building layout to photographs of these facilities. Since the layout compares well, the Department accepts BPXA's revised CGF/CCP building parameters.

BPXA stated they used the same building parameters for the off-site sources as developed for the November/December 2007 minor permit applications for GC1, GC-2, GC-3 and CPS. These applications are currently on hold and therefore, have not yet been reviewed by the Department. However, the Department confirmed that downwash was included for these sources and therefore, considers the assumed parameters adequate for an offsite inventory.

Off-Site Impacts

In a cumulative impact analysis, the applicant must include impacts from large sources located within 50 km of the applicant's SIA. These impacts from "off-site" sources are typically assessed through modeling. However, the off-site impacts in an AAAQS analysis can also be accounted for with ambient monitoring data, if representative data is available.

BPXA included the permitted stationary sources located within Prudhoe Bay, Milne Point, the Kuparuk River Unit, and Deadhorse in the modeled off-site inventory. They also included the Endicott (including the recently permitted "Liberty" project emission units), Badami and Northstar stationary sources.

The Department found a minor modeling error in regards to the Seawater Injection Plant East (SIPE) emission inventory. BPXA used a "907" and "908" nomenclature for the two main seawater injection turbines (tag number NGT-31-15101 and NGT-31-15102). However, they used a 907**C** and 908**C** (emphases added) nomenclature in the "source group" designations. The effect of this inconsistency is that AERMOD estimated the impacts from these units, but did *not* include those impacts when calculating the total impacts. The Department considers this error to be inconsequential since SIPE is relatively distant and not located within either of the predominate wind directions of CGF/CCP. The Department nevertheless confirmed this consideration by correcting the error and rerunning the worst-case averaging period (24-hour) and meteorological data year (1999). The maximum impact did not change.

Results and Discussion

The maximum SO_2 AAAQS impacts are shown in Tables 4 and 5. Table 4 provides the results for the 0.11 percent liquid fuel sulfur scenario. Table 5 provides the results for the 0.019 percent liquid fuel sulfur alternative. The background concentrations, total impacts and ambient standards are also shown in both tables. In all cases, the maximum impacts are no more than a third of the AAAQS.

Table 4: Maximum AAAQS Impacts When Liquid Fuel Sulfur = 0.11 percent

Air Pollutant	Avg. Period	Maximum Modeled Conc ($\mu g/m^3$)	Bkgd Conc ($\mu g/m^3$)	TOTAL IMPACT: Max conc plus bkgd ($\mu g/m^3$)	Ambient Standard ($\mu g/m^3$)
SO_2	3-hr	149.0	41.9	**191**	1,300
	24-hr	53.5	34.0	**88**	365
	Annual	7.1	2.6	**10**	80

Table 5: Maximum AAAQS Impacts With Alternative 0.019 percent Fuel Sulfur Limit at CGF

Air Pollutant	Avg. Period	Maximum Modeled Conc ($\mu g/m^3$)	Bkgd Conc ($\mu g/m^3$)	TOTAL IMPACT: Max conc plus bkgd ($\mu g/m^3$)	Ambient Standard ($\mu g/m^3$)
SO_2	3-hr	314.3	41.9	**356**	1,300
	24-hr	87.0	34.0	**121**	365
	Annual	7.1	2.6	**10**	80

The maximum SO_2 increment impacts are shown in Tables 6 and 7, along with the Class II increments. All of the maximum impacts are less than the applicable Class II increments.

Table 6: Maximum Increment Impacts When Liquid Fuel Sulfur = 0.11 percent

Air Pollutant	Avg. Period	Maximum Modeled Conc. ($\mu g/m^3$)	Class II Increment Standard ($\mu g/m^3$)
SO_2	3-hr	**143**	512
	24-hr	**52**	91
	Annual	**7**	20

Table 7: Maximum Increment Impacts With Alternative 0.019 percent Fuel Sulfur Limit at CGF

Air Pollutant	Avg. Period	Maximum Modeled Conc. ($\mu g/m^3$)	Class II Increment Standard ($\mu g/m^3$)
SO_2	3-hr	**314**	512
	24-hr	**87**	91
	Annual	**7**	20

It is important to note that since ambient concentrations vary with distance and direction from each emission unit, the maximum values shown represent the highest annual and high second high short term values value that may occur within the area. Except for maximum short term concentrations which are allowed to exceed the respective standards once per year, the concentrations at other locations within the modeling domain should be less than the values reported above.

ADDITIONAL IMPACT ANALYSES

Per 40 CFR 52.21(o), PSD applicants must assess the impact from the proposed project and associated growth on visibility, soils, and vegetation. BPXA provided the additional impact analysis in Section 2 of Attachment IV of their application. The Department's findings are reported below.

Visibility Impacts

The typical tool for assessing the potential visibility impact from North Slope sources is EPA's VISCREEN model. According to EPA's *Workbook for Plume Visual Impact Screening and Analysis (Revised)*, the pollutants of concern in a VISCREEN analysis are particulates and nitrogen oxides. SO_2 emissions are not included in the assessment. Therefore, this permit action should not affect the visibility of BPXA's exhaust plumes.

Vegetation Impacts

BPXA addressed this requirement in two manners. First, they referenced a 1989 – 1994 North Slope vegetation study conducted by the Boyce Thompson Institute for Plant Research that found no adverse impacts due to air contaminants. Second, they compared the modeled impacts to the secondary 3-hour SO_2 air quality standard and an annual sensitivity threshold for lichens.

The secondary air quality standards are set to protect public welfare, which includes protection against vegetative damage. As previously shown in Tables 4 and 5, the maximum 3-hour SO_2 impact is well below the AAAQS. Therefore, the project should not adversely affect the nearby vascular plants.

Lichens are more sensitive to air pollutants than vascular plants since they lack roots and derive all growth requirements from the atmosphere. Some lichen species are adversely affected when the annual average SO_2 concentration ranges between 13 to 26 $\mu g/m^3$.[19] While it is not known whether North Slope lichens have this same sensitivity, these values provide a surrogate measure of the potential sensitivity threshold.

The maximum annual average SO_2 impact from either scenario (10 $\mu g/m^3$) does *not* exceed the 13 $\mu g/m^3$ sensitivity threshold. Therefore, the local lichens should not be adversely impacted by the proposed increase in SO_2 emissions.

Soil Impacts

BPXA correctly noted that there is little information available regarding the effects of air pollutants on soils. They also noted that protecting the vegetative cover helps protect the soil. Since the air quality impacts are below the applicable vegetation thresholds, the soil should likewise be protected. BPXA's conclusions are reasonable.

[19] *Air Quality Monitoring on the Tongass National Forest* (USDA – Forest Service; September 1994).

Secondary Impacts

40 CFR 52.21(o)(2) requires PSD applicants to assess the impacts from general commercial, residential, industrial and other growth associated with the source or modification. BPXA does not expect significant changes in these categories. The Department accepts BPXA's assessment.

CONCLUSION

The Department reviewed BPXA's modeling analysis for the requested H_2S increase and concluded the following:

1. BPXA provided the source impact analysis required under 40 CFR 52.21(k) ***Source Impact Analysis***. The analysis adequately demonstrates that the SO_2 emissions associated with operating the CGF/CCP stationary source, within the constraints described in this memorandum, will not cause or contribute to a violation of the AAAQS provided in 18 AAC 50.010 or the maximum allowable increases (increments) provided in 18 AAC 50.020.
2. BPXA appropriately used the models and methods required under 40 CFR 52.21(l) ***Air Quality Models***.
3. BPXA provided the pre-application air quality analysis required under 40 CFR 52.21(m)(1) ***Preapplication Analysis***.
4. BPXA provided the additional visibility, soils, vegetation and secondary impact analysis required under 40 CFR 52.21(o) ***Additional Impact Analysis***.

The Department developed conditions in the CGF and CCP air quality control permits to ensure BPXA complies with the SO_2 ambient air quality standards and increments. These conditions are summarized below.

In the CGF Permit

5. For all diesel-fired emission units, limit the maximum fuel sulfur content to 0.11 percent, by weight.
6. For all gas-fired emission units, limit the maximum H_2S content to 105 ppm (on an instantaneous basis).
7. Comply with the unit specific annual operating limits shown in Table 3.[20]
8. Construct and maintain vertical, uncapped exhaust stacks for the three emergency generators (Tag No. NGI-19-2802, NGI-19-2819, NGI-19-2890), except when the liquid fuel sulfur content at CGF is less than or equal to 0.019 percent, by weight. When the fuel sulfur content is less than or equal to 0.019 percent, the stacks may be capped or have a horizontal discharge. The uncapped condition does not preclude the use of flapper valve rain covers, or other similar designs, that do not hinder the vertical momentum of the exhaust plume.

[20] The annual operating limits in Table 3 are being imposed to protect the annual average air quality standards and increments for the following pollutants: NOx, SO_2 and PM-10.

In the CCP Permit

1. For all diesel-fired emission units, limit the maximum fuel sulfur content to 0.11 percent, by weight.
2. For all gas-fired emission units, limit the maximum H_2S content to 105 ppm (on an instantaneous basis).
3. Comply with the unit specific annual operating limits shown in Table 3.[17]

Exhibit C: BACT Review

AIR QUALITY TITLE I PSD PERMITS
BACT FINDINGS REPORT (FINAL REPORT)

BP Exploration Alaska Inc. (BPXA)
Prudhoe Bay Central Compressor Plant (CCP) and Central Gas Facility (CGF)
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Under Contract 18-3001-12 and NTP 18-3001-12-9B

June 16, 2009

TABLE OF CONTENTS

Section 1 .... **1**

1.0. Executive Summary 1

Section 2 .... **3**

2.0 Background 3

- 2.1 Best Available Control Technology 3

3.0 BACT Determination for SO_2 5

- 3.1 Identify All Control Technologies (Step 1) 7
- 3.2 Eliminate Technically Infeasible Control Options (Step 2) 11
- 3.3 Rank the Remaining Control Technologies by Control Effectiveness (Step 3) 12
- 3.4 Evaluate the Most Effective Controls and Document Results (Step 4) 13
  - 3.4.1 H_2S Scavenging (Sulfa-Rite®) 14
  - 3.4.2 Liquid Redox (LO-CAT®) 15
  - 3.4.3 Amine Treatment System 15
  - 3.4.4 Limit Sulfur in Fuel Gas 15
- 3.5 Select BACT (Step 5) 16

4.0 Summary of Findings by Task 18

- 4.1 Completeness Review 18
- 4.2 Technical Accuracy 19
- 4.3 Cost Estimates and Cost Recovery 19
- 4.4 Errors and/or Uncertainties 19

5.0 Findings Summary 20

Appendix A – BACT Cost Analysis
Appendix B – RBLC Search Results

LIST OF TABLES

Tables **Page No.**

1 Technically Feasible Control Technology Summary 2
2 BPXA Emissions Increase from Fuel Gas Souring 3
3 BPXA CGF Combustion Equipment 5
4 Technically Feasible SO_2 Control Options 12
5 SO_2 Cost Effectiveness Summary for the Combustion Equipment 13
6 RBLC Search Results for SO_2 BACT Determination 17

1.0 Executive Summary

BP Exploration Alaska Inc. (BPXA) submitted the Prudhoe Bay Unit Prevention of Significant Deterioration (PSD) Construction Permit No. AQ0270CPT04 application on September 13, 2008 to the Alaska Department of Environmental Conservation (ADEC).

North Slope fuel gas souring has increased hydrogen sulfide (H_2S) concentrations in the fuel gas. The higher H_2S concentrations in the fuel gas result in higher sulfur dioxide (SO_2) emissions from the exhaust of Central Compressor Plant (CCP) and Central Gas Facility (CGF) combustion equipment. The CCP and CGF currently consists of the following fuel gas combustion equipment: twenty six (26) fuel gas fired turbines and eight (8) fuel gas fired heaters and two (2) reboilers and nine (9) flares. The CCP and CGF combustion equipment burns 295 million standard cubic feet of fuel gas per day (MMscf/d).

Under the US EPA permit PSD-X81-13, as amended August 29, 1997, SO_2 emissions from six (6) turbines and three (3) heaters at CGF are restricted. Under the ADEC permit 9873-AC006, issued July 15, 1998, the H_2S in the fuel gas at CGF is restricted for seven (7) turbines. These current limits are based on fuel gas conditions that existed in 1997. BPXA is unable to maintain continuous compliance with these current limits due to fuel gas souring unless emissions controls are added to the process.

BPXA is unable to determine to what level fuel gas H_2S levels will climb during the next 10 years, but estimates that H_2S fuel gas levels could increase to as high as 300 ppmv and elected to use this value as a conservative estimate for the BACT analysis. The resulting emission increase from the Fuel Gas Souring Project (Project) will exceed the significant emissions increase thresholds in 40 CFR 52.21(b)(2)(i) for SO_2, therefore the Project is classified as a PSD major modification for SO_2 and requires a Best Available Control Technology (BACT) assessment for SO_2. The Project does not increase emissions of volatile organic compounds (VOC), nitrogen (NO_x), carbon monoxide (CO), or for particulate matter (PM/PM_{10}).

BPXA performed a BACT analysis, which was reviewed for its technical accuracy, and adherence to accepted engineering cost estimation practices by Eastern Research Group, Inc. (ERG) under contract with the Alaska Department of Environmental Conservation. The purpose of this document is to report on ERG's assessment of BPXA's BACT analysis.

Table 1 provides a list of the control technologies that were determined to be technically feasible for the CCP and CGF combustion equipment. The shaded row indicates the control level for SO_2 proposed by the source as BACT.

Table 1. Technically Feasible Control Technology Summary

Control Technology	Annualized Costs (Revised)	Control Efficiency (%)	Cost $/ton removed	
			Applicant Estimate	Revised Estimate
LO-CAT®	**$ 38,201,145**	**99.7%**	**$ 15,526**	**$ 14,476**
Sulfa Treat®	**$ 33,461,456**	**98.7%**	**$ 13,420**	**$ 12,805**
Adsorption Process (Amine)	**$ 46,369,135**	**96.7%**	**$ 21,729**	**$ 18,113**
Limit Sulfur in Fuel	**-**	**-**	**-**	**-**

ERG agreed with BPXA's list of technically feasible control technologies. However, cost analyses were revised to adjust for the following items. Appendix A contains a comparison of the BPXA's cost analysis and the revisions made by ERG.

- Reduced contingency factor from 30 percent of the base equipment costs to 15 percent.

- Removed instrument and control costs from base equipment costs. Basic equipment and auxiliaries will include all appropriate controls.

- Reduced Amine painting costs from 6 percent of the base equipment costs to 4 percent.

2.0 Background

Alaska Department of Environmental Conservation contracted with Eastern Research Group, Inc. (ERG) to assess the BACT analyses submitted by BPXA and their adherence to accepted engineering standards. This report documents ERG's findings in the review of the BPXA BACT analyses.

2.1 Best Available Control Technology

ERG has reviewed the BACT analyses for SO_2 conducted by BPXA. The review included the identification of available technologies; the technical feasibility, control effectiveness, and energy, environmental and economic impacts of the controls.

The review has been conducted in accordance with state and federal rules and the conventional "Top-Down" Best Available Control Technology process. The steps for conducting a top-down BACT analysis are listed below:

Step 1 Identify all potentially available control options:

In Step 1, the applicant identifies all available control options for the emission unit and the pollutant under consideration. This includes technologies used throughout the world or emission reductions through the application of available control techniques, changes in process design, and/or operational limitations. To assist in identifying available controls, the applicant and the Department review the available controls listed on EPA's RACT/BACT/LAER Clearinghouse (RBLC) bulletin board where permitting agencies nationwide have listed the BACT control technologies imposed.

Step 2 Eliminate technically infeasible control options:

In Step 2, the applicant evaluates the technical feasibility of the various control options in relation to the specific emission unit under consideration. If the applicant can clearly document and demonstrate, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option, it is eliminated from further consideration in this step.

Step 3 Rank remaining control technologies by control effectiveness:

In Step 3, the remaining control options are listed in order of control effectiveness for the pollutant under review, with the most effective option at the top. In this step, the applicant also presents detailed information about the control efficiency, the expected emission rate and/or the expected emission reduction.

Step 4 Evaluate the most effective controls and document the results as necessary:

In Step 4, the energy, environmental, and economic impacts are considered to decide the final level of control. The applicant is responsible for presenting an objective evaluation of both the beneficial and adverse energy, environmental, and economic impacts. An applicant proposing to use the most effective option is not required to provide the detailed information for the less effective options.

Step 5 Select BACT:

In Step 5, the most effective control option not eliminated in step 4 is proposed as BACT for the pollutant and emission unit under review. The final BACT requirements determined for each emission unit are listed in this step.

The BACT analysis included in this findings report are based on the following information:

(a) The BACT analysis information submitted by BPXA on September 13, 2008 and additional information received on January 26, 2009 and May 20, 2009;

(b) Information from vendors, suppliers, and subcontractors; and

(c) The EPA RACT/BACT/LAER (RBLC) Clearinghouse.

The BACT Determinations for SO_2 follow in Section 3.0.

3.0 BACT Determination for SO_2

North Slope fuel gas souring has increased H_2S concentrations in the fuel gas. The higher H_2S concentrations in the fuel gas result in higher SO_2 emissions from the exhaust of CCP and CGF combustion equipment. Therefore, it is classified as a PSD major modification under 40 CFR 52.21. Fuel gas fired equipment at the CCP and CGF consists of the combustion equipment listed in the table below. Table 2 presents the projected potential SO_2 emissions and the maximum daily gas usage for the gas fired CCP and CGF equipment. These are important data relevant to the BACT analysis pertaining to cost effectiveness and the amount of SO_2 controlled based on the control efficiency of the technically feasible control technologies identified later in this document.

Table 2. BPXA CCP and CGF Combustion Equipment

Tag No.	Emission Unit Description	Projected SO_2 (tpy)	Maximum Daily Gas Usage (MMscf/d)
NGI-19-1883	GE Frame 6 Injection Compressor	117.9	13.59
NGI-19-1884	GE Frame 6 Injection Compressor	117.9	13.59
NGI-19-1885	GE Frame 6 Injection Compressor	117.9	13.59

NGI-19-1886	GE Frame 6 Injection Compressor	117.9	13.59
NGI-19-1801	Cooper-Rolls/RB211-24C Booster	63.7[a]	7.04
NGI-19-1802	Cooper-Rolls/RB211-24C Booster	63.7[a]	7.04
NGI-19-1805	Cooper-Rolls/RB211-24C Miscible Injectant	63.7[a]	7.04
NGI-19-1855	Cooper-Rolls/RB211-24C Miscible Injectant	63.7[a]	7.04
NGI-19-1806	GE MS5382C Refrigerant Compressor	95.5[a]	11.76
NGI-19-1856	GE MS5382C Refrigerant Compressor	95.5[a]	11.76
NGI-19-1857	GE MS5382C Booster Compressor	95.5	11.76
19-1408	IHI-John Zink Emergency Flare (HP Primary Pit)		
19-1409	IHI-John Zink Emergency Flare (LP Primary Pit)		
19-1410	IHI-John Zink Emergency Flare (HP Emergency Pit)	27.7	3
19-1411	IHI-John Zink Emergency Flare (LP Emergency Pit)		
19-1412	IHI-John Zink Emergency Flare (NGL Primary Pit)		
NGI-19-1401	Chiyoda-John Zink Hot Oil Heater	55.3[a]	5.98
NGI-19-1402	Chiyoda-John Zink Hot Oil Heater	55.3[a]	5.98
NGI-19-1403	Chiyoda-John Zink Hot Oil Heater	55.3[a]	5.98
NGT-18-1801	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1802	GE MS5371PATP w/LHE Gas Compressor	94.8	10.27
NGT-18-1803	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1804	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1805	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1806	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1807	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1808	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1809	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1810	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1811	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1812	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1813	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1876	GE MS5382C Tandem Compressor	98.2	10.63
NGT-18-1878	GE MS5382C Tandem Compressor	98.2	10.63
NGH-18-1410	Broach Glycol Heater	7.3	0.79
NGH-18-1491	Broach Glycol Heater	9.6	1.04
NGH-18-1492	Broach Glycol Heater	9.6	1.04

NGH-21-1501	Eclipse Glycol Heater	3.1	0.34
NGH-21-1502	Eclipse Glycol Heater	2.7	0.30
NGH-21-1503	BS&B TEG Reboiler	1.0	0.11
NGH-21-1504	BS&B TEG Reboiler	1.0	0.11
18-1403	John Zink HP/IP Emergency Flare	18.6	2.0
18-1494	John Zink STV Emergency Flare		
18-1496	Line Emergency Backup Flare		
18-1497	Line Emergency Backup Flare		
Total		**2,647**	**295**

[a]The projected potential SO_2 emission rate for these emission units is based on the assumption that the current EPA SO_2 ton-per-year limits will be increased as a result of a future application by the Permittee to revise the limit to the value shown here (i.e., to be based on 300 ppmv H_2S in the fuel gas instead of 30 ppmv H_2S).

There are two available SO_2 control approaches: 1) Prevent SO_2 emissions by reducing the H_2S concentrations through fuel gas treatment (H_2S Removal) or 2) Control SO_2 emissions in the flue gas exhaust, such as a desulfurization scrubber add-on control.

The following presents ERG's review of BPXA's BACT analysis for the available SO_2 control options using the step-by-step top-down approach described previously.

3.1 Identify All Control Technologies (Step 1)

<u>H_2S Removal Controls</u>

The following seven (7) control technologies for removal of H_2S emissions from North Slope fuel gas were identified:

1. Oil Reservoir Treatment Control (Biocide Injection)

H_2S levels in fuel gas are rising as reservoirs are souring across the North Slope as a result of waterflood operations used in enhanced oil recovery. Souring occurs when sulfate reducing bacteria which reduce the sulfate to H_2S, is injected with the water. Application of biocides into an oil field can reduce the activity of sulfate reducing bacteria and lower the H_2S content of the fuel gas.

Biocides introduced into the oilfield can retard the growth and proliferation of the sulfate reducing bacteria that are causing the H_2S levels in the gas to increase. To be effective, biocide treatments are often introduced as high dose slugs over extended intervals of time. The ultimate effectiveness of biocide injection on fuel gas on the North Slope is unknown.

2. H_2S Scavenging (SulfaTreat® and Sulfa-Rite®)

The scavenging process can be accomplished with either solid or liquid scavengers, which have nonregenerable reaction systems. The most common systems are marketed under SulfaTreat® and Sulfa-Rite® and both use an iron oxide scavenger. Gas Technology Products LLC (a Merichem Company) offers the Sulfur-Rite® technology for license. This technology is a representative H_2S scavenger system. The Sulfur-Rite® process is selective to H_2S and mercaptans, and is effective if the removal of other gas components, such as CO_2, is not required. In Sulfa-Rite® fuel gas is routed through a vessel containing a solid scavenger. Instead of merely absorbing H_2S, the Sulfur-Rite® process chemically changes H_2S into iron pyrite (FeS_4), which is a safe and stable compound. Sulfur-Rite® is designed to sweeten gas streams containing low levels of H_2S to less than 10 ppmv.

The most common liquid scavenger is an aminealdehyde condensate that is offered as a water-based solution. The scavenger liquid is typically injected directly into the gas stream using a static mixer or long length of pipe. The efficiency of the system is dependent on the degree of mixing and is, therefore, sensitive to flow fluctuations. Optimum performance of the scavenger requires that the fuel gas be 60 to 80 percent saturated before entering the vessel.

3. Liquid Redox (LO-CAT®)

The liquid redox process employs an aqueous based solution typically containing metal ions, usually iron, which are capable of transferring electrons in reduction-oxidation (redox) reactions. A commercial application offered by Gas Technology Products is called the LO-CAT® process. The LO-CAT® process converts H_2S to elemental sulfur using a patented, dual chelated iron catalyst, which has been shown to be environmentally safe.

This liquid redox technology uses a countercurrent liquid-gas absorption tower. The sour gas travels up the absorption tower and comes into contact with the patented LO-CAT® liquid solution flowing downward. Saturated sweet gas exits the top of the contactor. The liquid solution then travels to a reaction vessel in which air is bubbled through the liquid and the H_2S is converted into water and solid sulfur. A slip stream of this LO-CAT® solution is then filtered to remove the sulfur and is then returned to service in the countercurrent liquid-gas absorption tower. The solid elemental sulfur is filtered out as a cake of approximately 30 percent by weight solid (70 percent liquid) and sent to a landfill for disposal. Access to high purity fresh water is necessary to operate the LO-CAT® system to continually replenish to the LO-CAT® liquid.

The LO-CAT® processes have achieved H_2S removal efficiencies of greater than 99.9 percent in many different applications and industries. These applications range in size from a few standard cubic feet per minute (scfm) to several hundred MMscf/day and from a few pounds of sulfur produced to greater than 20 long tons of sulfur produced each day. The sour gas entering these LO-CAT® systems contain anywhere from 100 ppmv to 100 percent H_2S.

4. Thiopaq/Shell-Paques Technologies

Thiopaq/Shell-Paques are biotechnological processes for removing H_2S from gaseous streams by absorption into a mild alkaline solution followed by the oxidation of the absorbed sulfide to elemental sulfur by naturally occurring microorganisms.

Thiopaq is specifically designed for low pressure (near atmospheric) biogas streams. Thiopaq is a bio-catalyzed scrubber process which operates at ambient temperatures and pressures and does not require expensive catalysts and chemicals. The Thiopaq scrubber can be regarded as a caustic scrubber in which the spent caustic solution is continuously regenerated in the bioreactor. The H_2S removal efficiency can be as high as 99 percent.

The amount of water in the fuel gas, or the dew point, is very critical for the process and safety parameter. A sub dew point gas in an arctic environment can freeze lines, causing safety hazards and production downtime. Thiopaq technology uses water in the treatment system, so in addition to producing water for the Thiopaq technology, the fuel gas stream must be reconditioned to meet the -50^{o}F dew point requirement.

The Shell-Paques process is very similar to the Thiopaq process except it can accommodate low, midlevel, and high pressure fuel inlet gas streams (2 to 1,300 psig). The major difference between the two technologies allowing the application of the Shell-Paques process to higher fuel inlet pressures is the use of a flash vessel. In this process, a gas stream containing H_2S contacts an aqueous soda solution containing thiobacillus bacteria in an absorber. The soda absorbs the H_2S and is transferred to a flash vessel to remove dissolved hydrocarbon gases that become entrained in the spent scrubber solution. From the flash vessel, the solution is routed to an aerated atmospheric tank where the bacteria biologically convert the H_2S to elemental sulfur. Regenerated solvent from the bioreactor is pumped back to the scrubber for reuse. The biological sulfur slurry produced may be disposed of in a landfill, used for agricultural purposes, or purified to a high quality (>99 percent pure) sulfur cake. Applications range in size from approximately 200 lbs to 40 tons of sulfur produced per day.

5. Adsorption Process (Amine Treatment)

The Adsorption Process is a common process for sweetening sour natural gas that involves the use of an amine solution to remove the H_2S. The process is commonly referred to as the 'amine process' and is widely used across the U.S. in gas sweetening operations at oil and gas field production and processing plants. The sour gas is run through a packed or trayed tower, which contains the liquid amine solution. The amine system will saturate the fuel gas in the treatment process while removing the H_2S from the fuel gas. The solution has an affinity for sulfur and absorbs it. There are two principle amine solutions used, monoethanoliamine (MEA) and diethanolamine (DEA). Other amines are also available and may be blended to enhance their performance in specialized applications. Either of these compounds, in liquid form, will absorb sulfur compounds from natural gas as the gas passes through.

The effluent gas is virtually free of sulfur compounds and thus is no longer sour, but sweet. The rich amine is heated in a reboiler and routed to a still column where the amine is re-generated and an acid gas containing H_2S is generated. The acid gases must be routed to either a H_2S scavenging system, LO-CAT®, or Thiopaq process for sulfur recovery.

6. Oxidation Process (Xergy ACT)

The Xergy ACT (Advanced Catalytic Technology) is a dry gas phase direct oxidation technology to convert H_2S to elemental sulfur and water. The above dew point process, which is appropriate for the fuel gas stream at CGF, operates like a catalytic reactor in a traditional large scale sulfur recovery plant (Claus process).

The sour gas (untreated fuel gas) is heated to reaction temperature, after which air is added just before the mixture enters the fixed bed catalytic reactor. In the reactor, the oxidation of H_2S takes place. In the above dew point process, the elemental sulfur is not absorbed into the catalyst, but stays in the vapor phase and is recovered in the condenser. This process can be applied at pressures ranging from 5 psig to over 1,000 psig. The Xergy ACT process produces Claus quality (bright yellow) molten sulfur.

7. H_2S Seawater Scrubbing

In this process, fuel gas and seawater pass through a tower in which the fuel gas scrubs oxygen from the seawater and the seawater scrubs H_2S from the fuel gas. In the process of deaerating the seawater, the fuel gas is stripped of H_2S. The scrubbing tower saturates the fuel gas with corrosive seawater, which can produce extensive corrosion problems in the piping and heater burners. The fuel gas must be treated in a drying system to remove all the water prior to combustion.

SO_2 Controls

The following techniques to control SO_2 emissions in the exhaust of CCP and CGF combustion equipment were identified:

8. Limit Sulfur in Fuel

The SO_2 emissions are proportional to the sulfur content of the fuel. Therefore, limiting the sulfur content of the fuel can limit the SO_2 emissions effectively. (Note: BPXA's BACT analysis did not include this option, but included an option for Good Combustion Practices (GCP). GCP is appropriate for VOC, CO, or NO_X control, but not relevant for SO_2 control as SO_2 emissions are a function of the sulfur content of the fuel, and not a function of a poor combustion environment. In addition, fuel sulfur limits have formed the basis of ADEC's previous BACT determinations for SO_2 from fuel gas-fired equipment; therefore, ERG has added this control option to the BACT analysis and has dropped GCP from further consideration).

9. Flue Gas Desulfurization (FGD)

Flue gas desulfurization add-on control technology is commonly known as FGD and is the technology used for removing SO_2 from the exhaust flue gases. Absorption is a process used for scrubbing flue gases to remove SO_2. Devices that are based on absorption principles include packed towers, plate (or tray) columns, venturi scrubbers, and spray chambers.

In most cases the sorbent is an alkaline slurry, commonly limestone, slacked lime, or a mixture of slacked lime and alkaline fly ash, though many other sorbent processes exist. Pollutant removal may be enhanced by manipulating the chemistry of the absorbing solution so that it reacts with the pollutants, e.g., caustic solution for acid-gas absorption vs. pure water as a solvent. Caustic solution (sodium hydroxide, NaOH) is the most common scrubbing liquid used for acid-gas control (e.g., HCl, SO_2, or both), though sodium carbonate (Na_2CO_3) and calcium hydroxide (slacked lime, $Ca[OH]_2$) are also used.

When the acid gases are absorbed into the scrubbing solution, they react with alkaline compounds to produce neutral salts. Typical pollutant acid gas concentrations range from 250 to 10,000 ppmv. Most absorbers have removal efficiencies in excess of 90 percent.

3.2 Eliminate Technically Infeasible Control Options (Step 2)

The following control options have been determined to be technically infeasible:

1. Biocide technology cannot guarantee a required H_2S concentration level or a BACT compliance timeline. Therefore, the technology is deemed infeasible for this Project.

2. Thiopaq is a low pressure system (near atmospheric pressure) not suitable for the high pressure gas at CCP or CGF. Although the Shell-Paques biotechnology process accommodates high pressure gas inlet streams, it was also eliminated from further consideration based on information provided by the licensed vendor (NATCO). NATCO stated that the ratio of CO_2 to H_2S and CO_2 partial pressure are both too high for the Shell-Paques system.

3. The oxidation process is considered technically infeasible for the Project because it is not commercially available on this scale. The standard Xergy system uses a single reactor and has a maximum design gas treatment rate of 18 MMscf/d. The CCP and CGF Project requires 290 MMscf/d of gas treatment to fuel the

combustion equipment. The licensed vendor (Xergy) has no experience with treating this high volume of gas.

4. Seawater scrubbing is considered technically infeasible for the Project because the turbine manufacturers' tight restrictions on the amount of trace metals that may be contained in the fuel. In addition, seawater scrubbing produces a fuel gas that is saturated with corrosive seawater and contaminants, therefore requiring the following: additional fuel gas dehydration, new metallurgy throughout the gas lines, and replacement of existing turbine blades with those designed to withstand a marine environment. A review of technical literature shows no instances of seawater scrubbing being used to treat fuel gas being supplied to combustion turbines. Seawater scrubbing cannot reasonably be installed and operated with existing combustion turbines. It should be noted that Kuparuk Seawater Treatment Plant (KSTP) has two seawater de-aerator towers currently in service to de-aerate the water. A side effect of this process is a reduction in fuel gas H_2S at KSTP for a portion of the fuel gas burned at that source. The de-aerators produce extensive corrosion problems in the downstream piping and heater burners. Upgrades in the metallurgy have not solved KSTP's corrosion problems.

5. FGD technology is typically used in conjunction with high sulfur fuels such as coal and oil. North Slope fuel gas is more similar to natural gas than coal or oil. A search of the RBLC database (see Section 3.5) did not identify any add-on controls as a requirement for natural gas-fired equipment. The combustion of fuel gas containing 300 ppmv of H_2S will result in SO_2 concentrations at or below 10 ppmv. Typical applications of FGD technology are for exhaust streams with 100 ppmv to 2,000 ppmv SO_2. Therefore, this technology is not considered technically feasible for this project.

6. GCP, such as operator training and maintenance activities can be effective at reducing CO, VOC, and NO_X. The technology is not relevant for reducing SO_2 emissions. Therefore, GCP is deemed technically infeasible for this project.

3.3 Rank the Remaining Control Technologies by Control Effectiveness (Step 3)

The remaining technically feasible control technologies are listed in table below.

Table 3. Technically Feasible SO_2 Control Options

Control Technology	Control Efficiency
Liquid Redox (LO-CAT®)	99.7%
H_2S Scavenging (Sulfa-	98.7%
Adsorption Process (Amine)	96.7%
Limit Sulfur in Fuel	-

3.4 Evaluate the Most Effective Controls and Document Results (Step 4)

The most effective control applicable to the Prudhoe Bay CCP and CGF combustion equipment is control with LO-CAT®. This type of control can reduce the SO_2 emissions 99.7 percent. At a flowrate of 295 MMscf/d of fuel gas, a LO-CAT® system can reduce SO_2 emissions by 2,639 tons per year.

Fuel gas levels of 300 ppmv H_2S are considered the baseline conditions for the fuel gas. BPXA performed an economic impact analysis for the technically feasible control technologies. The results are summarized in the table below:

Table 4. SO_2 Cost Effectiveness Summary for the Combustion Equipment

Control Technology	Annualized Costs (Revised)	Total SO_2 Removed (tpy)	Cost $/ton removed	
			Applicant Estimate	Revised Estimate
Liquid Redox (LO-CAT®)	$38,201,145	2,639	$15,526	$14,476
H_2S Scavenging (Sulfa-Treat®) [1]	$33,461,456	2,613	$13,445	$12,806
Adsorption Process (Amine)	$46,369,135	2,560	$21,729	$18,113
Limit Sulfur in Fuel	-	-	-	-

1 - This cost value reflects only the scavenger material costs estimated by BPXA. No revisions were made to the estimates.

The BPXA's original application submitted in October 2008, indicated that the large quantity of scavenger material required by a Sulfa-Treat® system made it technologically in feasible. In response to ADEC's request on December 23, 2008 for additional information, on January 15, 2009 and May 20, 2009, BPXA provided more details indicating that the control technology was feasible, but not cost effective.

The control costs for the scavenging process Sulfa-Treat® do not include costs to control 295 MMscf/d. The analysis excluded the nine (9) emergency flares, or 8 MMscf/d of the total CFG-CCP fuel gas flowrate. Collectively this equipment accounted for a small portion of the total CFG-CCP fuel gas usage. Therefore, the $33 million annualized cost (shown in Table 4 above) represents the vast majority of systems costs; the 8 MMscf/d that was excluded accounts for less than 3 percent of the total CFG-CCP fuel gas flowrate. This exclusion will not dramatically affect the cost effectiveness.

The detailed cost estimates for the LO-CAT® and amine system were developed by BPXA based on treating 70 MMscf/d of fuel gas. Costs to treat 295 MMscf/d of fuel gas were projected using the "six-tenths rule". The six-tenths rule is a standard practice for projecting costs from a detailed estimate to similar equipment operating at a higher production rate. ADEC has accepted the six-tenths rule in previous BACT determinations including ConocoPhillips Permit No. 489CP10 issued September 17, 2004.

In reviewing BPXA's detailed cost analysis for the Sulfur-Treat®, LO-CAT® and amine system, ERG made revisions to some of the values and assumptions. Appendix A contains a line-by-line comparison of the BPXA cost analysis values and ERG's revisions. Table 4 above presents the following: the revised annualized cost, the applicants cost effectiveness, and the revised cost effectiveness. The revisions to the applicants cost are as follows:

- BPXA included a contingency factor of 30 percent of the base equipment costs. ERG does not agree with this level of uncertainty. The US EPA Cost Control Manual estimates contingency to be between 5 to 15 percent of total base equipment costs (EPA/452/B-02-001). Because of the scope and size of the CCP and CGF Project, ERG has estimated contingency using 15 percent of the base equipment costs.

- Equipment costs included three components: 1) Basic Equipment and Auxiliaries, 2) Instruments and Controls, and 3) Module Materials. Costs associated with the arctic grade module to house the basic treatment equipment are justified. However, details provided by BPXA and their consultant, WorleyParsons, did not adequately justify instruments and control costs. ERG believes the basic equipment and auxiliaries include all appropriate controls. ERG recalculated the cost of equipment excluding instruments and controls.

- BPXA included painting costs of 4 and 6 percent of the base equipment costs for the LO-CAT® and amine system, respectively. The Cost Control Manual estimates painting costs between 1 to 4 percent of total base equipment costs. It should be noted that retrofit installations will require additional ductwork and piping to tie in the control devices. Painting of the additional piping and ductwork is required. ERG has estimated the amine system painting costs using 4 percent of the base equipment costs.

The collateral impact clause of the BACT definition allows permitting authorities to temper the stringency of BACT in cases where the energy, environmental, or economic impacts that are associated with the use of a control option at a specific stationary source are viewed by the review agency as sufficiently adverse as to render the use of that technology inappropriate for a given stationary source. These impacts are discussed below for each technically feasible control option.

3.4.1 Liquid Redox (LO-CAT®)

The second most effective control applicable to the CCP and CGF combustion equipment is control with LO-CAT ®. The revised total capital cost to install a LO-CAT ® system capable of treating 295 MMscf/d of fuel gas per day is $200 million.

While technically not part of the control system, costs for both the LO-CAT® and amine system include a tri-ethylene glycol (TEG) contactor to remove water from the treated gas and a reboiler to reclaim the TEG, and a compressor to capture hydrocarbon vapors from the dehydration system for routing vapors back to the process gas system. The amount of water in the fuel gas, or the dew point, is a very important factor and safety parameter. A sub dew point gas in an arctic environment can freeze lines, causing safety hazards and production downtime. Gas is dehydrated to a -50°F dew point at the production facilities prior to being sent to the CCP and CGF. The LO-CAT® and dehydration system require approximately 530 kWe of power.

The LO-CAT® system would have several environmental impacts:

- The LO-CAT® system generates a sulfur waste product that would require disposal in the nearby landfill or injection down a waste well.
- LO-CAT® also uses a small amount of caustic solution to control pH in the oxidizer vessel.
- Some CO_2 would be absorbed into the chelate solution and ultimately converted to bicarbonate, which is eliminated with the sulfur cake. The reduced CO_2 results in a fuel gas with a higher heating value, which would create higher localized flame temperatures in the combustion system (due to lack of CO_2 diluent). NO_X emissions increase exponentially with flame temperature. Therefore, any significant change in the heating value could potentially result in an increase of NO_X emissions.

3.4.2 H_2S Scavenging (Sulfa-Treat®)

BPXA provided a detailed Sulfa-Treat ® cost analysis for controlling SO_2 emissions. The Sulfa-Treat ® system will require Sulfa-Treat ® skids, gas dehydration, high pressure water washing system, vacuum collection system, a water treatment system, and a water injection system. The revised total capital cost to install a system capable of treating 287 MMscf/d of fuel per day is $70 million (Table A-5, Appendix A).

The collateral environmental impacts of a Sulfa-Treat® system should also be noted; Each Sulfa-Treat® reaction vessels must be cleaned out, the spent scavenger loaded into trucks, and hauled to the North Slope Borough landfill at least once every month. For a combined operation of CCP and CGF, the process will generate approximately 400 tons of waste per month. This volume of solid waste would present significant challenges to the North Slope Borough.

3.4.3 Adsorption Process (Amine)

The revised total capital cost to install an Amine system capable of treating 295 MMscf/d of fuel gas per day is $246 million.

As discussed above the Amine system will include a gas dehydration unit with vapor recovery compressor. The Amine system and dehydration system require approximately 450 kWe of power.

The Amine system would have several environmental impacts:

- The Amine process generates a sulfur waste product that would require disposal in the nearby landfill or injection down a waste well.

Approximately 40 percent of the CO_2 would be absorbed into the amine solution. The reduced CO_2 results in a fuel gas with a higher heating value. A significant change in the heating value could potentially result in an increase of NO_X emissions.

3.4.4 Limit Sulfur in Fuel Gas

BPXA proposed GCP with no controls as BACT, based on the available fuel gas quality. As discussed above, GCP can be effective at reducing emissions of CO, VOC, and NO_X, but would not be effective in reducing SO_2 emissions. The most straightforward method of limiting SO_2 emissions is to burn fuels that contain less sulfur (H_2S).
Therefore, ERG recommends that a short term H_2S limit in fuel gas be included in the BPXA Prudhoe Bay - Fuel Gas Souring Permit.

3.5 Select BACT (Step 5)

BPXA contends that the control cost for each system, LO-CAT®, Sulfa-Treat®, and amine treatment, exceeds previous ADEC BACT determinations. At $12,806/ton of SO_2 removed, Sulfa-Treat® is the most affordable, technically feasible control system. It should be noted that this removal cost reflects only a portion of the systems total cost. LO-CAT® and amine treatment system are more expensive at $14,475 and $18,113 per ton of SO_2 removed, respectively.

<u>Additional Cost Discussions</u>

The BPXA's original application submitted in October 2008 did not include a discussion for bypassing the pollution control device with a portion of the combustion gas; a control approach, which would reduce the size of the equipment and therefore, the capital costs. In response to ADEC's request on December 23, 2008 for additional information, on January 15, 2009, BPXA indicated this practice is not allowed under BACT.

In the introduction section of the New Source Review DRAFT Manual (October 1990) it is stated that BACT is "an emission limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to the standard….".

BPXA indicated that by ConocoPhillips Alaska Inc. proposed this control approach in their 2004 H_2S/SO_2 BACT analysis for the Kuparuk Seawater Treatment Plant. ConocoPhillips proposed to by-pass a portion of the fuel gas to be treated to minimize costs. EPA Region 10 rejected the BACT on the basis that the gas was not being treated to the maximum potential of the technology. ERG agrees that the ConocoPhillips precedent applies to this CCP and CGF Project.

There are two additional factors that would further increase the cost per ton of SO_2 removed:

- The LO-CAT® and amine system cost do not include collection and disposal of the sulfur by-product.
- The LO-CAT® and amine solutions absorb CO_2, increasing the higher heating value of the fuel gas, reducing overall fuel gas usage, reducing the volume of fuel gas to be treated.

The Department will determine BACT based on the analysis discussed above.
Today, the Prudhoe Bay gas reservoir is H_2S level is at 30 ppmv. BPXA is unable to determine to what level fuel gas H2S will climb during the next 10 years, but estimates that fuel gas H_2S levels will increase to 300 ppmv and elected to use this value as a conservative estimate for the BACT analysis. If in the future fuel gas levels exceed 300 ppmv, then the BACT decision would also need to be revisited. ERG suggests that a short term H_2S limit in fuel gas be included in the BPXA Prudhoe Bay - Fuel Gas Souring Permit. Such a limit is consistent with other PSD permits in the RBLC database and the recently issued PSD permit for the BPXA Liberty Project (Permit No. AQ0181CPT06).

The RBLC database shows seventy two (72) SO_2 BACT determinations for natural gas-fired turbines and engines, with a rating between 40,000 and 400,000 hp, have been permitted under PSD since January 2003. Forty five (45) required fuel restriction such as allowing only pipeline quality natural gas to be combusted. None of the RBLC turbines and engines required an add-on control device as BACT.

The information available in the RBLC did not include removal costs. This could be because all chosen control options were no cost options, either a production limit or Good Control Practices. The results of the RBLC search for controlling SO_2 emissions from turbines can be found in Appendix B. For comparison, the four (4) most recent SO_2 BACT determinations from the RBLC search results are listed in the table below:

Table 5. RBLC Search Results for SO_2 BACT Determination

Source Details	Short Term Limits	Annual Emissions (tpy)
- BPXA Proposed BACT -		
Prudhoe Bay Unit Central Gas Facility		-
53,665 hp GE Frame 6 Injection Compressors (4) [1, 2]	300 ppmv H_2S [3]	-
33,300 hp Cooper-Rolls RB211 Booster Compressors (2) and Miscible Injectant Compressors (2) [2]		-

38,000 hp GE MS5382 Refrigerant Compressors (2) and Booster Compressor [1, 2]		-
85,000 hp (216 MMBtu/hr) Zink Heaters (3) [2]		-
- RBLC Database -		
American Municipal Power Generating Station; Source ID: OH-0310; Permit issued: 02/07/08;		
58,937 hp Boiler, Uncontrolled.	0.09 lb SO_2/hr	0.39
Thyssenkrupp Steel and Stainless USA, LLC; Source ID: AL-0230; Permit issued: 08/17/07;		
66,402 hp Reheat Furnace, Uncontrolled.	0.0006 lb SO_2/MMBtu	0.44
77,050 hp Reheat Furnace, Uncontrolled.	0.0006 lb SO_2/MMBtu	0.52
Ineos USA LLC - Chocolate Bayou Facility; Source ID: TX-0497; Permit issued: 08/29/06;		
46,935 hp Cogen. Trains 2 & 3; Low Sulfur Fuel.	12.66 lb SO_2/hr (=0.05 gr S/scf hourly)	10.06
Kern River Gas Transmission Company - Goodsprings Station Source ID: NV-0046; Permit issued: 05/16/06;		
15,422 hp Simple Cycle Turbine; Low Sulfur Fuel	0.33 lb/hr	1.45

1 – These units have SO_2 BACT limits of 30 ppmv under the ADEC permit 9873-AC006.
2 – ADEC has imposed an H_2S limit of 105 ppmv (not to exceed) for ambient protection.
3 – ERG has proposed a fuel sulfur limit as BACT.

4.0 Summary of Findings by Task

4.1 Completeness Review

The Department received the original application on September 22, 2008. On December 23, 2008, the Department requested that BPXA supply additional information regarding the BACT review. Additional information was received on January 23, 2009 and May 20, 2009.

BPXA has evaluated all known, commercially available lower-polluting processes, control technologies, and combinations of techniques for SO_2 control applicable to the eleven (11) fuel gas fired turbines and three (3) fuel gas fired heaters. BPXA provided data from which emission estimates and cost were extracted.

Specific H_2S removal processes evaluated by BPXA included the 1) Oil Reservoir Treatment Control (Biocide Injection); 2) H_2S Scavenging (SulfaTreat® and Sulfa-Rite®); 3) Liquid Redox (LO-CAT®); 4) Thiopaq/Shell-Paques Technologies; 5) Adsorption Process (Amine Treatment); 6) Oxidation Process (Xergy ACT); 7) H_2S Seawater Scrubbing; and 8) GCP. Flue gas desulfurization was also evaluated for emission control effectiveness and feasibility. Percent removals provided by BPXA and were consistent with technical literature.

ERG concurred with BPXA's list of control technologies considered and has added evaluation of a fuel sulfur limit as the baseline.

4.2 Technical Accuracy

The design features for each identified control technologies were appropriately considered by BPXA. The specifics of the plant, such as its remote location were considered in feasibility positions.

BPXA eliminated from consideration technically infeasible control options based on reasonable grounds. Findings were supported by BPXA with information from pollution control vendors and suppliers. ERG concurs with all technology elimination conclusions.

4.3 Cost Estimates and Cost Recovery

BPXA obtained cost estimates for each control technology from WorleyParsons and vendors. Installation costs such as insulation, piping, foundations, equipment setting, instrumentation, and electrical service connections were primarily consistent with the EPA Cost Control Manual (EPA/452/B-02-001).

To calculate the capital recovery costs BPXA assumed a 10-year expected useful life of each feasible control device and a seven (7) percent discount rate.

ERG made several other revisions to the cost analyses which have been listed in the Executive Summary and Section 3 of this document. The more significant revisions are reduction in contingency costs and the removal of extraneous instrument and control costs.

4.4 Errors and/or Uncertainties

The costs for the H_2S scavenging process (Sulfa-Treat®) reflected control for only 287 MMscf of the total 295 MMscf/d CFG-CCP fuel gas flowrate. To more accurately estimate control cost necessary to achieve the 98.7 percent control efficiency the price of the entire system should be quantified. However, the estimated cost effectiveness of the system ($12,806/ton) appears to make this technology cost-prohibitive.

A copy of the WorleyParsons cost estimate support package was provided in the BPXA application - Appendix C. Although each specific costs contained in Attachment V cannot be located in Appendix C, they are within an order of magnitude. These discrepancies appear to be attributed to the fact that the stated scope of the WorleyParsons package is a conventional LO-CAT® system to treat 141 MMscf/d of fuel gas, while system costs presented in Attachment V are scaled to treat 295 MMscf/d.

5.0 Findings Summary

ERG finds that:

1. The BPXA, CCP and CGF is an existing stationary source is classified as a Prevention Significant Deterioration (PSD) major source under the Departments Air Quality Control Regulations as listed in 18 AAC 50.300(c)(1).

2. The CCP and CFG Fuel Gas Souring Project is subject to major source review for SO_2 for having emissions increases greater than the PSD significance thresholds listed in 18 AAC 50.30(h)(3)(B)(ii) and (iii).

3. BPXA proposes SO_2 BACT for the twenty six (26) fuel gas fired turbines and eight (8) fuel gas fired heaters and two (2) reboilers to be GCP.

4. ERG recommends that a short term H_2S limit in the fuel gas be included in the BPXA Prudhoe Bay - Fuel Gas Souring Permit as BACT. Such a limit is consistent with other PSD permits in the RBLC database.

5. Several cost assumptions and factors were inappropriate, these include:

    - Reduced contingency factor from 30 percent of the base equipment costs to 15 percent.

    - Removed instrument and control costs from base equipment costs. Basic equipment and auxiliaries will include all appropriate controls.

    - Reduced Amine painting costs from 6 percent of the base equipment costs to 4 percent.

Additional information from BPXA may provide a more defensible justification for including these costs. As shown above, even with these cost reductions, ERG agrees with BPXA's position that Sulfa-Treat®, LO-CAT ®, and amine treatment are not cost-effective.

APPENDIX A

BACT COST ANALYSIS

Appendix A - Table A-1. Prudhoe Bay - Initial Capital Costs for

LO-CAT on the Fuel Gas Fired Turbines, Heaters, Reboilers and Flares

DIRECT COSTS 1) Purchased Equipment		Technology Factor	Applicant (70 MMscfd)	Applicant (295 MMscfd)	Revised (70 MMscfd)	Revised (295 MMscfd)	
a) Basic Equipment and Auxiliaries (A)	Equipment Vendors & WorleyParsons	-	8,681,137		8,681,137		
b) Instruments and Controls	WorleyParsons	-	1,964,840		-		(1)
c) Module Materials	WorleyParsons	-	10,438,519		10,438,519		
d) Freight (Anchorage, N. Slope, Sealift)	0.10 * (a+b+c) + WorleyParsons	-	6,590,700	31%	6,590,700		
e) Taxes	0.03 * (a+b+c)	-	632,535		573,590		(2)
Total Equipment Cost (B)	B = (a + b + c + d + e)	-	28,307,731	67,063,214	26,283,946	62,268,710	(2)
2) Anchorage Construction Costs			-				(2)
a) Foundations and Supports	0.002 (a+b+c)	0.002	51,780		38,239		(2)
b) Erection and Handling	Equipment Factor * (a+b+c)	0.242	5,139,965		4,626,957		(2)
c) Mechanical	Equipment Factor * (a+b+c)	0.055	1,171,180		1,051,581		(2)
d) Instrumentation	Equipment Factor * (a+b+c)	0.069	1,458,742		1,319,256		(2)
e) Electrical	Equipment Factor * (a+b+c)	0.142	3,023,192		2,714,991		(2)
f) Piping	Equipment Factor * (a+b+c)	0.254	5,399,625		4,856,393		(2)
g) Insulation	Equipment Factor * (a+b+c)	0.031	655,132		592,709		(2)
h) Painting	Equipment Factor * (a+b+c)	0.026	547,785	4%	497,111		(2)
Total Anchorage Construction Costs (C)	C = (a + b + c + d + e + f + g + h)	-	17,457,401	41,357,939	15,697,238	37,187,975	(2)
3) North Slope Construction Costs							
a) Foundations and Supports	Equipment Factor * (a+b+c)	0.007	141,680		133,838		(2)
b) Erection and Handling	Equipment Factor * (a+b+c)	0.022	463,760		420,632		(2)
c) Mechanical	Equipment Factor * (a+b+c)	0.075	1,595,000		1,433,974		(2)
d) Instrumentation	Equipment Factor * (a+b+c)	0.009	197,606		172,077		(2)
e) Electrical	Equipment Factor * (a+b+c)	0.040	851,898		764,786		(2)
f) Piping	Equipment Factor * (a+b+c)	0.090	1,908,280		1,720,769		(2)
g) Insulation	Equipment Factor * (a+b+c)	0.009	189,851		172,077		(2)
h) Painting	Equipment Factor * (a+b+c)	0.009	196,460		172,077		(2)
Total North Slope Construction Costs (D)	D = (a + b + c + d + e + f + g + h)	-	5,544,535	13,135,434	4,990,230	11,822,243	(2)
Total Direct Costs (TDC)	B + C + D	-	51,309,667	121,556,588	46,971,413	111,278,928	(2)
INDIRECT COSTS							
4) Engineering and Procurement	WorleyParsons	-	11,410,300		11,410,300		
5) Unit Operator Costs (UOC)	0.13 * TDC	-	6,670,257		6,106,284		(2)
6) Start-up	Included in UOC	-	-				
7) Performance Test	0.015 * B	-	426,671		394,259		(2)
8) License Fee	Vendor Data or 0.015 * B	-	131,000		131,000		
Total Indirect Costs (IDC)			18,636,173	44,150,542	18,041,843	42,742,528	(2)
Total Direct Costs + Indirect Costs (TDC + IDC)			69,945,840	165,707,130	65,013,256	154,021,456	(2)
9) Contingency	30 percent of (TDC + IDC)	-	20,983,752	49,712,139	9,751,988	46,206,437	(3)
Total Capital Costs (TCC) [TDC + IDC + Contingency]		-	90,929,591	215,419,268	74,765,245	200,227,893	(2)

FOOTNOTES:

(1) = Removed instrument and control costs from base equipment costs. Basic equipment and auxiliaries include all appropriate controls.

(2) = These calculations dependant on purchased equipment costs, which have been revised.

(3) = Reduced contingency factor from 30 percent of the base equipment costs to 15 percent.

Appendix A - Table A-2. Prudhoe Bay - Annualized Costs for

LO-CAT on the Fuel Gas Fired Turbines, Heaters, Reboilers and Flares

Direct Costs		Technology Factor	Applicant (70 MMscfd)	Applicant (295 MMscfd)	Revised (70 MMscfd)	Revised (295 MMscfd)	
1) Operating Labor (E):	1 hr per 12 hr shift (730 hrs/yr @ $138/hr)	-	100,740	238,661	100,623	238,384	(2)
2) Supervisory Labor	[0.15 * (E)]	-	15,111	35,799	15,093	35,758	(2)
3) Maintenance Labor:	1.1 hr per 12 hr shift (803 hrs/yr @ $138/hr)	-	110,814	262,527	110,686	262,223	(2)
4) Parts and Materials	[100 percent of maintenance labor]	-	110,814	262,527	110,686	262,223	(2)
5) Utilities							
a) Electricity	(0.10/kW-hr, 265 kWe, 530 kWe, 8,760 hr/yr)	-	232,140	549,958	232,140	549,958	
b) Additional fuel	Not estimated	-	-	-	-	-	
6) Chemicals	WorleyParsons	-	711,251	1,685,009	710,860	1,684,082	
Total Direct Costs							(2)
Indirect Costs							
7) Overhead	[included in No. 1) and No. 3)]	-	-	-	-	-	
8) Property Tax	(0.01 * TCC)	-	909,296	2,154,193	747,652	2,002,279	(2)
9) Insurance	(0.01 * TCC)	-	909,296	2,154,193	747,652	2,002,279	(2)
10) G&A Charges	(0.02 * TCC)	-	1,818,592	4,308,385	1,495,305	4,004,558	(2)
11) Capital Recovery (CRF * TCC)							
	Capital Recovery Factor (CRF)(7 percent ROR, 10-year life = 0.1424)	-	12,946,328	30,670,857	10,644,889	28,507,947	(2)
Total Indirect Costs		-	16,583,512	39,287,628	13,635,499	36,517,063	(2)
TOTAL ANNUALIZED COSTS		-	17,294,763	40,972,637	14,346,358	38,201,145	(2)
Tons/year of SO2 Removed		-	610	2,639	610	2,639	
Emission reduction		-					
COST EFFECTIVENES		-	28,370	15,526	23,530	14,476	(2)

FOOTNOTES:

(1) = Removed instrument and control costs from base equipment costs. Basic equipment and auxiliaries include all appropriate controls.

(2) = These calculations dependant on purchased equipment costs, which have been revised.

Appendix A - Table A-3. Prudhoe Bay - Initial Capital Costs for

Amine System on the Fuel Gas Fired Turbines, Heaters, Reboilers and Flares

DIRECT COSTS 1) Purchased Equipment		Technology Factor	Applicant (70 MMscfd)	Applicant (295 MMscfd)	Revised (70 MMscfd)	Revised (295 MMscfd)	
a) Basic Equipment and Auxiliaries (A)	Equipment Vendors & WorleyParsons	-	17,394,100		17,394,100		
b) Instruments and Controls	WorleyParsons	-	2,296,230		-		(1)
c) Module Materials	WorleyParsons	-	10,440,265		10,440,265		
d) Freight (Anchorage, N. Slope, Sealift)	0.10 * (a+b+c) + WorleyParsons	-	7,706,483		7,706,483		
e) Taxes	0.03 * (a+b+c)	-	903,918		835,031		(2)
Total Equipment Cost (B)	B = (a + b + c + d + e)	-	38,740,996	91,780,430	36,375,879	86,177,284	(2)
2) Anchorage Construction Costs							(2)
a) Foundations and Supports	0.002 (a+b+c)	0.002	51,780		55,669		(2)
b) Erection and Handling	Equipment Factor * (a+b+c)	0.171	5,139,937		4,759,676		(2)
c) Mechanical	Equipment Factor * (a+b+c)	0.039	1,171,180		1,085,540		(2)
d) Instrumentation	Equipment Factor * (a+b+c)	0.087	2,607,120		2,421,590		(2)
e) Electrical	Equipment Factor * (a+b+c)	0.164	4,936,438		4,564,836		(2)
f) Piping	Equipment Factor * (a+b+c)	0.319	9,603,510		8,879,162		(2)
g) Insulation	Equipment Factor * (a+b+c)	0.044	1,322,555		1,224,712		(2)
h) Painting	Equipment Factor * (a+b+c)	0.042	1,265,460	6%	1,113,375		(4)
Total Anchorage Construction Costs (C)	C = (a + b + c + d + e + f + g + h)	-	26,098,008	61,828,209	24,104,560	57,105,576	(2)
3) North Slope Construction Costs							
a) Foundations and Supports	Equipment Factor * (a+b+c)	0.005	141,680		139,172		(2)
b) Erection and Handling	Equipment Factor * (a+b+c)	0.015	463,760		417,515		(2)
c) Mechanical	Equipment Factor * (a+b+c)	0.053	1,595,000		1,475,221		(2)
d) Instrumentation	Equipment Factor * (a+b+c)	0.012	355,904		334,012		(2)
e) Electrical	Equipment Factor * (a+b+c)	0.047	1,408,663		1,308,215		(2)
f) Piping	Equipment Factor * (a+b+c)	0.104	3,131,700		2,894,774		(2)
g) Insulation	Equipment Factor * (a+b+c)	0.009	282,040		250,509		(2)
h) Painting	Equipment Factor * (a+b+c)	0.013	405,240		-		(4)
Total North Slope Construction Costs (D)	D = (a + b + c + d + e + f + g + h)	-	7,783,987	18,440,870	6,819,419	16,155,734	(2)
Total Direct Costs (TDC)	B + C + D	-	72,622,991	172,049,508	67,299,858	159,438,594	(2)
INDIRECT COSTS							
4) Engineering and Procurement	WorleyParsons	-	13,798,368		13,798,368		
5) Unit Operator Costs (UOC)	0.13 * TDC	-	9,440,989		8,748,982		(2)
6) Start-up	Included in UOC	-	-				
7) Performance Test	0.015 * B	-	581,115		545,638		(2)
8) License Fee	Vendor Data or 0.015 * B	-	Included with (A)				
Total Indirect Costs (IDC)			23,820,472	56,432,549	23,092,988	54,709,082	(2)
Total Direct Costs + Indirect Costs (TDC + IDC)			96,443,463	228,482,057	90,392,846	214,147,676	(2)
9) Contingency	30 percent of (TDC + IDC)	-	28,933,039	68,544,617	13,558,927	32,122,151	(3)
Total Capital Costs (TCC) [TDC + IDC + Contingency]			125,376,502	297,026,674	103,951,773	246,269,827	(2)

FOOTNOTES:

(1) = Removed instrument and control costs from base equipment costs. Basic equipment and auxiliaries include all appropriate controls.

(2) = These calculations dependant on purchased equipment costs, which have been revised.

(3) = Reduced contingency factor from 30 percent of the base equipment costs to 15 percent.

(4) = Reduced Amine painting costs from 6 percent of the base equipment costs to 4 percent.

Appendix A - Table A-4. Prudhoe Bay - Annualized Costs for
Amine System Fuel Gas Fired Turbines, Heaters, Reboilers and Flares

Direct Costs		Technology Factor	Applicant (70 MMscfd)	Applicant (295 MMscfd)	Revised (70 MMscfd)	Revised (295 MMscfd)	
1) Operating Labor (E):	1 hr per 12 hr shift (730 hrs/yr @ $138/hr)	-	100,740	238,661	100,623	238,661	(2)
2) Supervisory Labor	[0.15 * (E)]	-	15,111	35,799	15,093	35,799	(2)
3) Maintenance Labor:	1.1 hr per 12 hr shift (803 hrs/yr @ $138/hr)	-	110,814	262,527	110,686	262,527	(2)
4) Parts and Materials	[100 percent of maintenance labor]	-	110,814	262,527	110,686	262,527	(2)
5) Utilities		-					
a) Electricity	(0.10/kW-hr, 265 kWe, 530 kWe, 8,760 hr/yr)	-	197,100	466,945	197,100	466,945	
b) Additional fuel	Not estimated	-	-	-	-	-	
6) Chemicals	WorleyParsons	-	80,000	189,526	80,000	189,526	
Total Direct Costs			614,579	1,455,985	614,188	1,455,058	(2)
Indirect Costs							
7) Overhead	[included in No. 1) and No. 3)]	-	-	-	-	-	
8) Property Tax	(0.01 * TCC)	-	1,253,765	2,970,267	1,039,518	2,462,698	(2)
9) Insurance	(0.01 * TCC)	-	1,253,765	2,970,267	1,039,518	2,462,698	(2)
10) G&A Charges	(0.02 * TCC)	-	2,507,530	5,940,533	2,079,035	4,925,397	(2)
11) Capital Recovery (CRF * TCC)							
	Capital Recovery Factor (CRF)(7 percent ROR, 10-year life = 0.1424)	-	17,850,793	42,289,916	14,800,394	35,063,283	(2)
Total Indirect Costs		-	22,865,853	54,170,983	18,958,465	44,914,076	(2)
TOTAL ANNUALIZED COSTS		-	23,480,432	55,626,969	19,572,653	46,369,135	(2)
Tons/year of SO2 Removed		-	591	2,560	591	2,560	
Emission reduction		-					
COST EFFECTIVENES		-	39,710	21,729	33,101	18,113	(2)

FOOTNOTES:

(1) = Removed instrument and control costs from base equipment costs. Basic equipment and auxiliaries include all appropriate controls.

(2) = These calculations dependant on purchased equipment costs, which have been revised.

Appendix A - Table A-5. Prudhoe Bay - Initial Capital Costs for
Sulfa Treat ® System on the Fuel Gas Fired Turbines, Heaters, Reboilers and Flares

DIRECT COSTS		Technology Factor	Applicant (136 MMscfd)	Applicant (287 MMscfd)	Revised (287 MMscfd)	
1) Purchase Equipment						
a) Basic Equipment and Auxiliaries (A)	Equipment Vendors & WorleyParsons	-	7,144,100	12,660,750	12,660,750	
b) Instruments and Controls	0.1 * A	-	714,410	1,266,075	-	(1)
c) Module Materials	WorleyParsons	-	6,865975	10,997,398	10,997,398	
d) Freight (Anchorage, N. Slope, Sealift)	0.10 * (a+b+c) + WorleyParsons	-	4,257,049	6,276,622	6,276,622	
e) Taxes	0.03 * (a+b+c)	-	441,735	747,727	709,744	(2)
Total Equipment Cost (B)	B = (a + b + c + d + e)	-	19,423,269	31,948,572	30,644,514	
2) Anchorage Construction Costs						
a) Erection and Handling	Equipment Factor * (a+b+c)	-	2,121,600	2,883,200	2,883,200	
b) Instrumentation	Equipment Factor * (a+b+c)	-	542,952	962,217	962,217	
c) Electrical	Equipment Factor * (a+b+c)	-	1,157,344	2,051,042	2,051,042	
d) Piping	Equipment Factor * (a+b+c)	-	1,878,327	3,328,755	3,328,755	
e) Insulation	Equipment Factor * (a+b+c)	-	271,476	481,109	481,109	
f) Painting	Equipment Factor * (a+b+c)	-	257,188	455,787	455,787	
g) Labor adjustment			771,563	1,367,361	1,367,361	
Total Anchorage Construction Costs (C)	C = (a + b + c + d + e + f + g)	-	7,000,450	11,529,481	11,529,481	
3) North Slope Construction Costs						
a) Foundations and Supports	Equipment Factor * (a+b+c)	-	43,320	60,648	60,648	
b) Erection and Handling	Equipment Factor * (a+b+c)	-	530,400	720,800	720,800	
c) Instrumentation	Equipment Factor * (a+b+c)	-	28,576	50,643	50,643	
d) Electrical	Equipment Factor * (a+b+c)	-	128,594	227,894	227,894	
e) Piping	Equipment Factor * (a+b+c)	-	681,118	1,207,076	1,207,076	
f) Insulation	Equipment Factor * (a+b+c)	-	14,288	25,322	25,322	
g) Painting	Equipment Factor * (a+b+c)	-	28,576	50,643	50,643	
h) Labor adjustment			35,721	63,304	63,304	
Total North Slope Construction Costs (D)	D = (a + b + c + d + e + f + g + h)	-	1,490,593	2,406,330	2,406,330	
Total Direct Costs (TDC)	B + C + D	-	27,914,312	45,884,383	45,884,383	
INDIRECT COSTS						
4) Engineering and Procurement	WorleyParsons	-	5,303,719	8,718,032	8,718,032	
5) Unit Operator Costs (UOC)	0.13 * TDC	-	3,628,861	5,964,970	5,964,970	
6) Start-up	Included in UOC	-	-			
7) Performance Test	0.015 * B	-	291,349	479,229	479,229	
8) License Fee	Vendor Data or 0.015 * B	-	-			
Total Indirect Costs (IDC)			9,223,929	15,162,230	15,162,230	
Total Direct Costs + Indirect Costs (TDC + IDC)			37,138,240	61,046,613	61,046,613	
9) Contingency	30 percent of (TDC + IDC)	-	11,141,472	18,313,984	9,156,992	(3)
Total Capital Costs (TCC) [TDC + IDC + Contingency]			48,279,712	79,360,597	70,203,605	

FOOTNOTES:
(1) = Removed instrument and control costs from base equipment costs. Basic equipment and auxiliaries include all appropriate controls.
(2) = These calculations dependant on purchased equipment costs, which have been revised.
(3) = Reduced contingency factor from 30 percent of the base equipment costs to 15 percent.

Appendix A - Table A-6. Prudhoe Bay - Annualized Costs for
Sulfa Treat ® System on the Fuel Gas Fired Turbines, Heaters, Reboilers and Flares

Direct Costs		Technology Factor	Applicant (136 MMscfd)	Applicant (287 MMscfd)	Revised (295 MMscfd)	
1) Operating Labor (E):	1 hr per 12 hr shift (730 hrs/yr @ $109/hr)	-	79,570	79,570	79,570	
2) Supervisory Labor	[0.15 * (E)]	-	11,936	11,936	11,936	
3) Maintenance Labor:	1.1 hr per 12 hr shift (803 hrs/yr @ $109/hr)	-	87,527	87,527	87,527	
4) Parts and Materials	[100 percent of maintenance labor]	-	175,054	175,054	175,054	
5) Sulfa Treat XLP (Media)	WorleyParsons	-	5,678,815	12,417,526	12,417,526	
6) Sulfa Treat Changeout Cost	WorleyParsons		3,606,618	6,924,706	6,924,706	
7) Sulfa Treat Disposal Cost	WorleyParsons		500,000	960,000	960,000	
Total Direct Costs			10,139,520	20,656,319	20,656,319	
Indirect Costs						
7) Overhead	[included in No. 1) and No. 3)]	-	-	-	-	
8) Property Tax	(0.01 * TCC)	-	482,797	793,606	702,036	(2)
9) Insurance	(0.01 * TCC)	-	482,797	793,606	702,036	(2)
10) G&A Charges	(0.02 * TCC)	-	965,594	1,587,212	1,404,072	(2)
11) Capital Recovery (CRF * TCC)						
	Capital Recovery Factor (CRF)(7 percent ROR, 10-year life = 0.1424)	-	6,875,031	11,300,949	9,996,993	(2)
Total Indirect Costs		-	8,806,219	14,475,373	12,805,138	(2)
TOTAL ANNUALIZED COSTS		-	18,945,739	35,131,691	33,461,456	(2)
Tons/year of SO_2 Removed		-	1,164	2,613	2,613	
Emission reduction		-				
COST EFFECTIVENES		-	16,276	13,445	12,806	(2)

FOOTNOTES:

(1) = Removed instrument and control costs from base equipment costs. Basic equipment and auxiliaries include all appropriate controls.

(2) = These calculations dependant on purchased equipment costs, which have been revised.

(3) = Reduced contingency factor from 30 percent of the base equipment costs to 15 percent.

APPENDIX B

RBLC SEARCH RESULTS

RBLC ID		Company	Facility	Permit Date	(Last Update)	Process	Capacity	SO_2 Emission Limit	Control Technology	Basis
	AZ-0047	Dome Valley Energy Partners	Wellton Mohawk Generating Station	12/01/04	01/31/06	GE7FA Combined Cycle Combustion Turbine	170 MW	0.0023 lb/MMBtu 4.7 lb/hr	Not Listed	BACT-PSD
	AZ-0047	Dome Valley Energy Partners	Wellton Mohawk Generating Station	12/01/04	01/31/06	Siemens Westinghouse Combined Cycle Turbine	180 MW	0.0023 lb/MMBtu 5.3 lb/hr	Not Listed	BACT-PSD
	AZ-0049	Allegheny Energy Supply, LLC	La Paz Generating Facility	09/04/03	07/24/07	2 Siemens Westinghouse Combustion Turbines	1080 MW	0.0021 lb/MMBtu 4.6 lb/hr	Not Listed	BACT-PSD
	AZ-0049	Allegheny Energy Supply, LLC	La Paz Generating Facility	09/04/03	07/24/07	2 GE Combustion Turbines	1040 MW	0.0021 lb/MMBtu 5.1 lb/hr	Not Listed	BACT-PSD
*	CA-1152	Calpine Western Regional Office	Pastoria Energy Facility	12/23/04	12/04/07	3 GE 7FA Combustion Turbines	168 MW ea	3.5 lb/hr (3 hr avg)	Pipeline Quality Natural Gas	BACT-PSD
	FL-0244	Florida Power and Light	Martin Plant	04/16/03	12/22/03	4 Combined Cycle Natural Gas Fired Turbines	170 MW	0.02 gr S/scf	Low Sulfur Fuel	BACT-PSD
	FL-0245	Florida Power and Light	Manatee Plant - Unit 3	04/15/03	08/30/06	4 Combined Cycle Natural Gas Fired Turbines	170 MW	0.02 gr S/scf	Low Suflur Fuel	BACT-PSD
	FL-0256	Progress Energy	Hines Power Block 3	09/08/03	08/30/06	Combined Cycle Turbnine	1830 MMBt/hr	None	Low Sulfur Fuel	BACT-PSD
	FL-0261	City of Tallahassee	Arvah B. Hopkins Generating Station	10/26/04	03/17/05	2 GE LM6000PC Combustion Turbines	445 MMBtu/hr 50 MW	1.13 lb/hr	Low Sulfur Fuel	BACT-PSD
	FL-0263	Florida Power and Light	Turkey Point Power Plant	02/08/05	01/12/06	4 Gas Fired Combustion Turbines	170 MW ea	0.02 gr S/scf	Low Suflur Fuel	BACT-PSD
	FL-0265	Progress Energy	Hines Power Block 4	06/08/04	01/12/06	Combined Cycle Turbine	530 MW	0.02 gr S/scf	Low Suflur Fuel	BACT-PSD
	FL-0279	Tampa Electric Company	Polk Energy Station	04/28/06	10/02/07	Simple Cycle Gas Turbine Units 4 and 5	1834 MMBtu/hr 80 MW	0.02 gr S/scf 0.7 lb/hr 18.6 tpy	Natural Gas Firing	BACT-PSD
*	LA-0192	Cresent City Power LLC	Cresent City Power	06/06/05	01/15/08	2 Gas Turbines	2006 MMBtu/hr 187 MW	101.1 lb/hr 0.18 gr S/scf 44.2 tpy	Low Sulfur Fuel	BACT-PSD
	MD-0032	Mirant Mid-Atlantic, LLC	Dickerson	11/05/04	04/12/05	Unit 5 GE Frame 7F Combustion Turbine	196 MW	12 lb/hr (3 hr avg)	Low Sulfur Fuel	BACT-PSD
	MD-0032	Mirant Mid-Atlantic, LLC	Dickerson	11/05/04	04/12/05	Unit 4 GE Farme 7F Combustion Turbine	196 MW	11 lb/hr (3 hr avg)	Low Sulfur Fuel	BACT-PSD
	MI-0361	South Shore Power LLC		01/30/03	01/23/04	2 Combined Cycle Combustion Turbines	172 MW ea	0.002 gr S/scf	Pipeline Quality Natural Gas	BACT-PSD
	MI-0362	Midland Cogeneration Venture Limited Partnership		04/21/03	01/23/04	11 Combined Cycle Turbines	984 MMBtu/hr	0.002 gr S/scf	Low Sulfur Fuel	BACT-PSD

	MI-0363	Bluewater Energy Center, LLC		01/07/03	01/23/04	3 Combined Cycle Combustion Turbines	180 MW ea	177 tpy	Pipeline Quality Natural Gas Good Combustion Techniques	BACT-PSD
	MI-0365	Mirant Wyandotte, LLC		01/28/03	08/30/06	2 Combined Cycle Combustion Turbines	2200 MMBtu/hr	0.008 gr S/scf 53.4 tpy	Use of Sweet Natural Gas	BACT-PSD
	MN-0053	Minnesota Municipal Power Agency	Fairbault Energy Park	07/15/04	09/21/04	Mitsubishi 501F Combined Cycle Turbine	1876 MMBtu/hr 280 MW	0.8 gr S/scf 132 tpy	Low Sulfur Fuel	BACT-PSD
	MN-0054		Mankato Energy Center	12/04/03	08/24/06	2 Combined Cycle Combustion Turbines	1916 MMBtu/hr	0.008 gr S/scf	Low Suflur Fuel	BACT-PSD
	MS-0057	South Mississippi Electrick Power Association	Silver Creek Generating Station	05/29/03	10/17/03	3 Simple Cycle Turbines	1109.3 MMBtu/hr	6.1 lb/hr 20.1 tpy	Not Listed	BACT-PSD
	MS-0073	Reliant Energy, LLC	Choctaw County	11/23/04	01/25/05	3 Combustion Turbines (AA-001 to AA-003)	230 MW ea	1.38 lb/hr ea 6.04 tpy ea	Not Listed	BACT-PSD
	MS-0079	Warren Power, LLC	Peaking Plant	01/30/03	09/28/05	4 Gas Fired Simple Cycle Combustion Turbines	959.8 MMBtu/hr	2.9 lb/hr ea 2.9 tpy ea	Clean Fuel; Natural Gas Firing	BACT-PSD
	NC-0101	Forsyth Energy Projects LLC	Forsyth Energy Plant	09/29/05	08/30/06	3 Combined Cycle Combustion Turbines	1844.3 MMBtu/hr	0.006 lb/MMBtu(3 hr avg)	Low Sulfur Fuels	BACT-PSD
	NE-0022	Grand Island Utilities	C.W. Burdick Generating Station	06/22/04	07/08/04	Gas Fired Combustion Turbine	1 MMscf/hr	5.4 lb/hr 2.5 lb/MMBtu	Low Sulfur Fuel	Other
	NV-0033	El Dorado Energy, LLC		08/19/04	09/15/04	Combined Cycle Turbine and Cogeneration	475 MW	1.03 lb/hr per CTG	Not Listed	Other
	NV-0037	Sempra Energy Resources	Copper Mountain Power	05/14/04	12/20/05	2 GE Combustion Turbines	172 MW ea	5.1 lb/hr	Pipeline Quality Natural Gas	BACT-PSD
	NV-0038	Ivanpah Energy Center, LP		12/29/03	12/21/05	2 Westinghouse Model 501FD Combined Cycle Turbines	500 MW	1.55 lb/hr 6.75 tpy	Pipeline Quality Natural Gas	BACT-PSD
*	NV-0046	Kern River Gas Transmission Company	Goodsprings Compressor Station	05/16/06	12/03/07	3 Combustion Turbines - Simple Cycle Model MARS 100-T15000S	97.81 MMBtu/hr 11.5 MW	0.0034 lb/MMBtu 0.33 lb/hr	Low Sulfur Fuel	BACT-PSD
	OH-0252	Duke Energy Hanging Rock, LLC	Hanging Rock Energy Facility	12/28/04	07/05/05	4 GE 7FA Combined Cycle Combustion Turbines	172 MW ea	14.4 lb/hr with duct burners 11.0 lb/hr w/o duct burners 0.02 gr S/scf	Low Sulfur Fuel	BACT-PSD
	OH-0254	Duke Energy North America	Washington County LLC	08/14/03	07/05/05	2 GE 7FA Combined Cycle Turbines	170 MW ea	14.5 lb/hr with duct burners 11.2 lb/hr w/o duct burners 0.02 gr S/scf	Low Sulfur Fuel	BACT-PSD
	OH-0291	First Energy	West Lorain Plant	11/17/04	08/31/06	5 Simple Cycle Combustion Turbines	85 MW	0.6 lb/hr each 39.9 tpy total	Low Sulfur Fuel	BACT-PSD

	OH-0304	Rolling Hills Generating LLC	Rolling Hills Plant	01/17/06	05/08/07	5 Siemens Westinghouse W501F Simple Cycle Gas Fired Turbines	209 MW	5.9 lb/hr 11.8 tpy	Natural Gas Firing	BACT-PSD
	OK-0090	Duke Energy	Stephens LLC	03/21/03	10/10/03	2 Combined Cycle Combustion Turbines	1701 MMBtu/hr	0.006 lb/MMBtu	Pipeline Quality Natural Gas	BACT-PSD
	OK-0096	Redbud Energy LP	Redbud Power Plant	06/03/03	04/23/04	Combustion Turbine	1832 MMBtu/hr	0.003 lb/MMBtu	Low Suflur Fuel	BACT-PSD
	OR-0043	Umatilla Generating Company LP	Umatilla Generating Company, LP	05/11/04	07/01/04	2 GE Frame 7FB Combined Cycle Gas Turbines	2007 MMBtu/hr	8000 ppmw	Low Sulfur Fuel <0.8% by weight	N/A, NSPS
	TX-0374	BP Amoco Chemical Company	Chocolate Bayou Plant	03/24/03	01/04/05	2 Cogeneration Trains 2 and 3, GT-2 and 3	70 MW	0.05 gr S/scf hourly 0.005 gr S/scf annual 12.66 lb/hr ea 10.06 tpy	Low Sulfur Fuels Good Combustion Practices	Other
	TX-0456	Exxon Mobil Corporation	Baytown Olefins Plant	06/13/03	08/02/07	Natural and Process Gas Fired Turbine w/o duct burners	95.5 MW	2.15 lb/hr 12.4 tpy	Not Listed	BACT-PSD
	TX-0456	Exxon Mobil Corporation	Baytown Olefins Plant	06/13/03	08/02/07	Natural and Process Gas Fired Turbine w/ duct burners	95.5 MW	11.15 lb/hr 12.4 tpy	Not Listed	BACT-PSD
	TX-0456	Exxon Mobil Corporation	Baytown Olefins Plant	06/13/03	08/02/07	Gas Fired Combustion Turbine	164 MW	26.14 lb/hr 12.24 tpy	Not Listed	BACT-PSD
	TX-0456	Exxon Mobil Corporation	Baytown Olefins Plant	06/13/03	08/02/07	3 Gas Fired Turbines	39 MW ea	7.3 lb/hr 6.39 tpy	Not Listed	BACT-PSD
	TX-0457	City Public Service	Leon Creek Plant	06/26/03	08/14/07	4 GE LM6000 Combustion Turbine	Not Listed	1.3 lb/hr 5.5 tpy	Good Combustion of Natural Gas	BACT-PSD
	TX-0458	Duke Energy LP	Jack County Power Plant	07/22/03	08/14/07	Natural Gas Fired Combustion Turbine	Not Listed	14.5 lb/hr 58.7 tpy	Low Sulfur Fuel	BACT-PSD
	TX-0467	Ennis-Tractebel LLP	Ennis Tractebel Power	03/24/03	10/01/07	2 Westinghouse Model 501G Combustion Turbines	230 MW	4.8 lb/hr 6.6 tpy	Use of Pipeline Quality Natural Gas	BACT-PSD
	TX-0468	Union Carbide Corporation	Texas City Operations	01/23/03	10/01/07	Gas Fired Combustion Turbine	12000 lb/hr	3.8 lb/hr 15 tpy	Not Listed	BACT-PSD
	TX-0469	Texas Petrochemicals LP	Houston Facility	10/08/03	10/01/07	2 GE 7EA Combined Cycle Turbine	664 MMBtu/hr	37.06 lb/hr 28.2 tpy	Sweet Natural Gas Good Combustion Practices	BACT-PSD
	TX-0487	Rohm and Hass Texas Inc.	Lone Star Plant	03/24/05	10/15/07		Not Listed	0.03 lb/hr0.12 tpy	Not Listed	RACT
*	TX-0497	Ineos USA LLC	Chocolate Bayou Facility	08/29/06	10/02/07	Cogeneration Train 2 and 3	35 MW	12.66 lb/hr 0.05 gr S/scf hourly 10.06 tpy	Low Sulfur Fuels	BACT-PSD

*	TX-0509	Ponderosa Pine Energy Partners	Cogeneration Facility	03/15/06	11/08/07	Simple Cycle Gas Turbine	375 MMBtu/hr 250 MW	87.22 lb/hr 92.5 tpy	Natural Gas Firing	BACT-PSD
	VA-0265	Dynegy	Chickahominy Power	01/10/03	08/31/06	4 501F Simple Cycle Combustion Turbines	1862 MMBtu/hr	1.1 lb/hr ea	Low Sulfur Fuels Good Combustion Practices	BACT-PSD
	VA-0269	Cinergy Capital and Trading	Martinsville Plant	01/08/03	06/23/03	4 Simple Cycle Combustion Turbines	82 MW ea	4 lb/hr 9.8 tpy	Low Sulfur Fuels Good Combustion Practices	Other
	VA-0279	Cinergy Capital and Trading	Martinsville Plant	01/08/03	06/28/04	4 Simple Cycle Combustion Turbines	82 MW ea	4 lb/hr 9.8 tpy 0.15 gr S/scf hourly 0.08 gr S/scf annual	Low Sulfur Fuels	BACT-PSD
	VA-0280	Old Dominion Electric Cooperative	Marsh Plant	02/14/03	06/28/04	GE Model PG7241S Simple Cycle Combustion Turbine	1624 MMBtu/hr	0.2 gr S/scf hourly 0.02 gr S/scf annual	Low Suflur Fuel	BACT-PSD
	VA-0281	Dynegy	Chickahominy Power	01/10/03	08/31/06	4 501F Simple Cycle Combustion Turbines	182.6 MW	1.1 lb/hr ea 0.002 gr S/scf 56 tpy	Low Sulfur Fuel	BACT-PSD
	VA-0282	Old Dominion Electric Cooperative	Louisa Plant	03/11/03	06/21/04	GE Model PG7241S Simple Cycle Combustion Turbine	1624 MMBtu/hr	0.2 gr S/scf hourly 0.02 gr S/scf annual	Low Suflur Fuel	BACT-PSD
	VA-0287	James City Energy Park, LLC	James City Energy Park	12/01/03	03/29/04	Combined Cycle Natural Gas Turbine	1973 MMBtu/hr	11.4 lb/hr	Low Suflur Fuel	BACT-PSD
	VA-0289	Duke Energy Wythe, LLC		02/05/04	03/25/04	Combined Cycle Turbine	170 MW	1.74 lb/hr w/o duct burner 2.08 lb/hr w/ duct burner 0.003 gr S/scf	Low Sulfur Fuels Good Combustion Practices	BACT-PSD
	WA-0291	Wallula Generation, LLC	Wallula Plant	01/03/03	08/31/06	4 Combined Cycle Natural Gas Fired Turbines	1300 MW	0.35 ppmdv @ 15%O2 (1 hr avg) 4.5 lb/hr (24 hr avg)	Natural Gas Firing	Other
	WA-0315	Sumas Energy 2	Generation Facility	04/17/03	08/31/06	2 Combined Cycle Combustion Turbines	660 MW	1 ppmvd (1 hr avg) 189 lb/day each 0.002 gr S/scf (7 day avg) 0.011 gr S/scf annual	Low Sulfur Fuel	BACT-PSD
*	WA-0328	BP West Coast Products, LLC	Cherry Point Cogeneration Project	01/11/05	08/14/07	3 GE 7FA Combustion Turbines	174 MW ea	None	Limit Fuel Use to Natural Gas	BACT-PSD
	WI-0240	Wisconsin Electric Power	Concord	01/26/06	11/29/06	Combustion Turbine	100 MW	0.0068 lb/MMBtu	Natural Gas Firing	BACT-PSD
*	AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	08/17/07	04/03/08	NATURAL GAS-FIRED REHEAT FURNACE (LA21) (MULTIPLE EMISSION POINTS)	169 MMBtu/hr	0.0006 lb/MMBtu	Not Listed	BACT-PSD

	OH-0310	AMERICAN MUNICIPAL POWER	AMERICAN MUNICIPAL POWER GENERATING STATION	02/07/08	05/13/08	AUXILIARY BOILER	150 MMBtu/hr	0.09 lb/hr	Not Listed	BACT-PSD
	AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	08/17/07	04/03/08	NATURAL GAS -FIRED ANNEALING FURNACE (LA43) (MULTIPLE EMISSION POINTS)	196.4 MMBtu/hr	0.0006 lb/MMBtu	Not Listed	BACT-PSD
*	TX-0499	SANDY CREEK ENERGY ASSOCIATES	SANDY CREEK ENERGY STATION	07/24/06	11/08/07	AUXILLARY BOILER	175 MMBtu/hr	0.11 lb/hr	Not Listed	BACT-PSD
	WI-0228	WISCONSIN PUBLIC SERVICE	WPS - WESTON PLANT	10/19/04	08/31/06	AUXILLIARY NAT. GAS FIRED BOILER (B25, S25)	229.8 MMBtu/hr	0.0006 lb/MMBtu	Natural Gas	BACT-PSD
	MI-0368	MICHIGAN PAPERBOARD COMPANY	MICHIGAN PAPERBOARD COMPANY	09/08/04	10/25/04	BOILER	185 MMBtu/hr	280 lb/hr	Not Listed	BACT-PSD
	OH-0241	MILLER BREWING COMPANY	MILLER BREWING COMPANY - TRENTON	05/27/04	07/11/05	BOILER (2), NATURAL GAS	238 MMBtu/hr	1.6 lb/MMBtu	Not Listed	BACT-PSD
	WV-0023	LONGVIEW POWER, LLC	MAIDSVILLE	03/02/04	12/06/05	AUXILIARY BOILER	225 MMBtu/hr	0.004 lb/hr	Low Sulfur Natural Gas Fuel	BACT-PSD
	VA-0270	VIRGINIA COMMONWEALTH UNIVERSITY	VCU EAST PLANT	03/31/03	07/15/03	BOILER NATUAL GAS	150 MMBtu/hr	0.1 lb/hr	Good Combustion Practices. Low sulfur fuel	BACT-PSD
	VA-0278	Virginia Commonwealth University	VCU EAST PLANT	03/31/03	06/21/04	BOILER, NATURAL GAS, (3)	150.6 MMBtu/hr	0.1 lb/hr	Low Sulfur Fuel	BACT-PSD