Exhibit 1

AR-EPA-H-4

U.S. Environmental Protection Agency (EPA) Region 10, Statement of Basis for the Draft Outer Continental Shelf Permit to Construct and Title V Air Quality Operating Permit No. R10OCS030000, Shell Offshore Inc., Beaufort Sea Exploration Drilling Program
(July 22, 2011)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
SEATTLE, WASHINGTON

STATEMENT OF BASIS
FOR DRAFT
OUTER CONTINENTAL SHELF
PERMIT TO CONSTRUCT AND TITLE V AIR QUALITY OPERATING PERMIT NO. R10OCS030000

SHELL OFFSHORE INC.
CONICAL DRILLING UNIT KULLUK
BEAUFORT SEA EXPLORATION DRILLING PROGRAM

Date of Permit: July 22, 2011

TABLE OF CONTENTS

Because exploration drilling programs are not included in the list of source categories subject to a 100-tpy PSD applicability threshold, the requirements of the PSD program apply if the project PTE is at least 250 tpy of a regulated NSR pollutant. PSD review also applies if GHG PTE is at least 100,000 tpy. From the pre-permitted PTE shown in Table 2-1, it is evident that Shell‘s Beaufort Sea exploration drilling program would be a major PSD source for CO, SO_2, NO_X and GHG because each would exceed the major source thresholds if federally enforceable limits were not imposed via the permit. Therefore, based on the pre-permitted PTE of the Shell project, federally enforceable limits for CO, SO_2, NO_X, and GHGs must be included in the OCS/Title V permit in order for Shell‘s OCS source to qualify as a ―synthetic minor” not subject to PSD.

Shell has estimated its emissions of hazardous air pollutants (HAP) from its Beaufort Sea exploration drilling program at 3.4 tpy for all HAP combined. See April 29, 2011 letter from Shell to Region 10 in the administrative record for detailed HAP emissions calculations. Based upon these calculations, the project is an area source of HAP, rather than a major source of HAP.

2.6 Other Standards and Requirements Applicable to the OCS Source

As discussed above, OCS sources located beyond 25 miles of a state‘s seaward boundaries are subject to the NSPS in 40 CFR Part 60; the PSD program in 40 CFR § 52.21 if the OCS source is also a PSD major stationary source or if there is a major modification to a PSD major stationary source; standards promulgated under Section 112 of the CAA if rationally related to the attainment and maintenance of federal and state ambient air quality standards or the requirements of Part C of Title I of the CAA; and the operating permit program under Title V and Part 71. See 40 CFR § 55.13(a), (c), (d)(2), (e), and (f)(2), respectively. See also 40 CFR § 71.4(d).

Part 55 makes the requirements of Part 71 applicable to this OCS source. See 40 CFR § 55.13(f). Part 71 requires a Title V permit to address all ―applicable requirements” as that term is defined in 40 CFR Part 71.2. The following subsections of this Section discuss the categories of Title V ―applicable requirements” for the Shell exploratory operations, as well as other requirements that must be included in the OCS/Title V permit.

2.6.1 Part 55 Requirements as Applicable Requirements

Standards and requirements to control air pollution from OCS sources under Section 328 of the CAA are included in the definition of applicable requirement in 40 CFR § 71.2 and apply to the source as provided in Part 55. Accordingly, all requirements of Part 55 applicable to the OCS source have been included in the draft OCS/Title V permit and are discussed in Section 3, this includes the COA requirements incorporated by reference in 40 CFR § 55.14.

2.6.2 NAAQS as Applicable Requirements for Title V Temporary Sources

Region 10 interprets the CAA and EPA regulations to require that a temporary source seeking a Title V permit demonstrate that it will not cause or contribute to a violation of the NAAQS at all locations where it is authorized to operate. Section 504(e) of the CAA authorizes a Title V permitting authority to issue a single permit authorizing emissions from similar operations by the same source owner at multiple temporary locations, provided that the permit includes conditions that will assure compliance with all applicable requirements at all locations. EPA regulations at 40 CFR § 71.6(e) provide that a ―temporary source” is any source that moves at least once during the term of a Title V permit. The application submitted by Shell requests authorization to conduct exploratory drilling at multiple temporary locations during the term of the permit, and the project is therefore a temporary source under Title V.

Section 504(e) further provides that requirements applicable to Title V temporary sources include, but are not limited to, ―ambient standards and compliance with any applicable increment or visibility requirements under Part C" of Title I of the Act. In turn, implementing regulations at 40 CFR § 71.2 define ―applicable requirements" as including ―(13) any national ambient air quality standard [NAAQS] or increment or visibility requirements under Part C, Title I of the Act, but only as it would apply to temporary sources permitted pursuant to section 504(e) of the Act." EPA included the same language in 40 CFR § 70.2. When EPA adopted its Part 70 regulations, the Agency interpreted Section 504(e) of the Act to make compliance with the NAAQS an applicable requirement for temporary sources. 57 Fed. Reg. 32550, 32276 (July 21, 1992) (―Under the Act, NAAQS implementation is a requirement imposed on States in the SIP; it is not imposed directly on a source. In its final rule, EPA clarifies that the NAAQS and the increment and visibility requirements under part C of title I of the Act are applicable requirements for temporary sources only."). Based on this prior interpretation by EPA, Region 10 reads the definition of ―applicable requirement" in 40 CFR 71.2 to mean that compliance with the NAAQS is an applicable requirement for all Title V temporary sources and therefore this source.

The definition of ―applicable requirement" in 40 CFR 71.2 says that the NAAQS, increment, and visibility requirements are applicable requirements ―only as it would apply to temporary sources permitted pursuant to Section 504(e) of the Act." Section 504(e) of the CAA identifies applicable requirements for temporary sources as including ―ambient standards and compliance with any applicable increment or visibility requirements under part C." Region 10 interprets these provisions to mean that NAAQS are applicable requirements for all Title V temporary sources, but that increment and visibility requirements are applicable requirements only if such sources would otherwise be subject to PSD. Because the language in section 504(e) of the Clean Air Act uses the term ―applicable" before ―increment or visibility requirements under part C," Region 10 interprets Section 504(e) to only make increment and visibility requirements ―applicable requirements" for a temporary source when they would otherwise be ―applicable" to a new major stationary source or major modification to an existing major stationary source in a permit required under Part C of the Act. Because the permittee is taking limits such that the source will not be a new major stationary source subject to PSD, the increment and visibility requirements under 40 CFR § 52.21 and Part C of the Act are not ―applicable" in this instance.

Thus, the NAAQS are considered ―applicable requirements" for the Kulluk and the OCS/Title V permit must contain terms and conditions that ensure compliance with the NAAQS at all relevant locations. The application submitted by Shell includes an analysis of the air quality impacts of the emissions from its exploratory operations on the NAAQS. The air quality analysis generally follows the regulations and guidance applicable to air quality analyses supporting permits issued under the PSD program. Part 71 does not describe how a Title V temporary source should demonstrate compliance with the NAAQS. In the absence of regulations or guidance setting out the requirements for a demonstration that the terms and conditions of a Title V permit for a temporary source will assure compliance with NAAQS at all authorized locations or operation, Region 10 believes that following the regulations and guidance for conducting an air quality analysis with respect to NAAQS under the PSD program is an appropriate approach. *See* 40 CFR Part 52, Appendix W (―Industry and control agencies have long expressed a need for consistency in the application of air quality models for regulatory purposes . . . The *Guideline* provides a common basis for estimating the air quality concentrations of criteria pollutants used in assessing control strategies and developing emission limits.”)

While EPA recognizes that temporary sources must demonstrate compliance with the NAAQS at all authorized locations, in the context of OCS permits, there remains some uncertainty as to whether Section 328 of the CAA should be read by EPA to require such a showing for areas of ambient air over the OCS or solely on land. EPA is therefore currently assessing how to apply the NAAQS to OCS sources beyond 25 miles of a state‘s seaward boundary on the Outer OCS. And, for sources located within 25 miles of a state seaward boundary on the Inner OCS, it is considering how to apply those regulatory requirements consistent with the mandate in CAA § 328(a)(1) that requirements to control pollution from OCS sources located within 25 miles of the state seaward boundary –shall be the same as would be applicable if the source were located in the corresponding onshore area.” Under any readings of these provisions, Region 10 believes that the permit applicant has made a sufficient showing to meet this applicable requirement. As discussed in more detail in Section 4 below, Region 10 reviewed and analyzed Shell‘s application and air quality analysis and concluded that it demonstrates that the emissions impact from its exploratory operations, when operating in compliance with the terms and conditions of the draft OCS/Title V permit, will not cause or contribute to a violation of any NAAQS at any location in the ambient air over any point on the OCS or within the state seaward boundary.[14] Therefore, resolving the point of compliance questions is not necessary for this permitting action.

As also discussed below in Section 3, the draft OCS/Title V permit includes emission limits, operating restrictions, and associated monitoring, recordkeeping, and reporting requirements to ensure emissions authorized under the permit will not cause or contribute to a violation of any NAAQS.

2.6.3 New Source Performance Standards as Applicable Requirements

Standards promulgated under Section 111 of the CAA are –applicable requirements” under 40 CFR § 71.2 and Section 111 standards promulgated under 40 CFR Part 60 (Part 60) apply to OCS sources as provided in 40 CFR § 55.13(c). Specific NSPS subparts in Part 60 apply to a source based on the source category, equipment capacity, and the date when the equipment commenced construction or modification. All emission units operating on the Kulluk are potentially subject to NSPS regulations because each is an emission unit on an OCS source. The application submitted by Shell provides that the Kulluk will contain emission units in four NSPS source categories: stationary compression-ignition internal combustion engines, boilers, incinerators, and fuel tanks. The requirements of applicable NSPS subparts for stationary compression-ignition internal combustion engines and incinerators are discussed in Section 3 of the SOB.

NSPS Subparts K, Ka, and Kb: 40 CFR Part 60, Subparts K, Ka, and Kb apply to petroleum liquids tanks as follows: K applies to tanks with capacity greater than 40,000 gallons that commenced construction or modification between March 8, 1974 and May 19, 1978; Ka applies to tanks with capacity greater than 40,000 gallons that commenced construction or modification

[14] As discussed in more detail below, the draft OCS/Title V permit includes a condition that supports excluding the area within 500 meters of the hull of the Kulluk from ambient air.

Note that EPA amended NSPS Subpart CCCC on March 21, 2011 to eliminate this exemption. See 76 Fed. Reg. 15704. On May 18, 2011, however, EPA stayed the effectiveness of the amendments until the proceedings for judicial review of these rules are completed or the EPA completes its reconsideration of the rules, whichever is earlier. The permit will be amended, as necessary, to reflect the outcome of the NSPS Subpart CCCC rule review consistent with the Title V program's permit reopening provisions as provided in Condition A.7.

4. AIR QUALITY ANALYSIS

As discussed in Section 2 above, Shell's permit applications triggered several COA and Title V requirements to assess the expected air quality impacts from the Kulluk and Associated Fleet and demonstrate that project emissions do not cause or contribute to a violation of the NAAQS. The details regarding these requirements are found in Appendix A (Region 10 Technical Support Document Review of Shell's Air Quality Analysis). To address these requirements, Shell submitted an ambient air quality analysis in support of their Kulluk permit application.

Region 10 has reviewed Shell's submittal and determined that Shell's analysis adequately shows that operating the Kulluk and Associated Fleet within the requested constraints will not cause or contribute to violations of the NAAQS. Region 10's assessment of Shell's analysis is fully described in Appendix A and is summarized below.

Region 10 evaluated Shell's modeling analysis under the guidance established in 40 CFR Part 51, Appendix W, *Guideline on Air Quality Models* (Appendix W). Shell used the American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) system of programs to estimate most of their ambient impacts. Region 10 used qualitative assessments to evaluate the ozone and lead impacts.

The AERMOD Modeling System consists of various modules. Shell used the AERMET component to process their meteorological data during periods of broken ice, and a non-Guideline model, the Coupled Ocean-Atmospheric Response Experiment (COARE) bulk flux algorithm to process the meteorological data during open water periods. Shell also used the Plume Volume Molar Ratio Method (PVMRM) to estimate their nitrogen dioxide (NO_2) impacts. The COARE and PVMRM algorithms have not been approved by EPA for general use, but have been approved by Region 10 under the case-by-case alternative modeling provisions of Appendix W. Region 10 therefore specifically requests public comment on the suitability of these modeling algorithms for this permitting action.

The maximum modeled NO_2, SO_2, PM_{10}, $PM_{2.5}$, and CO impacts, background concentrations, total impacts, and NAAQS are summarized below in Table 4-1. The maximum impacts occur within 500 meters of the Kulluk and rapidly decrease as the distance from the Kulluk increases. All of the total impacts are less than the NAAQS at all locations that constitute ambient air. See Section 3.4 Conditions D.5 and D.6 of the SOB.

Table 4-1: Modeled Impacts at the Location of Maximum Impact

Air Pollutant	Averaging Period	Shell Only Impacts (without background) (μg/m^3)	Background Concentration (μg/m^3)	Total Impact Including Background (μg/m^3)	NAAQS (μg/m^3)	Total Impact as a % of NAAQS
NO_2	1-hour	110.6	40.9	**151.5**	188	81%
	Annual	4.4	11	**15.4**	100	15%
$PM_{2.5}$	24-hour	17.0	17	**34**	35	97%
	Annual	1.0	4	**5.0**	15	33%
PM_{10}	24-hour	20.8	53	**73.8**	150	49%
SO_2	1-hour	14.0	29	**43.0**	196	22%
	3-hour	8.9	29	**37.9**	1,300	3%
	24-hour	2.8	22	**24.8**	365	7%
	Annual	0.2	4	**4.2**	80	5%
CO	1-hour	1,268	1,742	**3,010**	40,000	8%
	8-hour	712	1,094	**1,806**	10,000	18%

The total 24-hour $PM_{2.5}$ impact at the location of maximum modeled impact is very close to the applicable NAAQS. This is partially due to the conservative assumptions used by Shell in its modeling analysis. For example, the 24-hour $PM_{2.5}$ NAAQS is based on a three-year average of the 98th percentile of the 24-hour concentrations. For modeling purposes, Shell assumed the Kulluk never relocates during the entire drilling season and returns to the same location each successive drilling season. This assumption produces the largest possible predicted impact, but overstates what would really occur under the more likely scenario of periodically relocating the Kulluk. In addition, the background concentration is a very conservative estimate of expected concentrations offshore in the vicinity of Shell's operations and includes days during which the measured background concentrations onshore were likely influenced by local dust. Average background concentrations of $PM_{2.5}$ are much lower, at approximately 2 μg/m^3.

The total impact (Kulluk and Associated Fleet plus background) in the local communities of Nuiqsut, Deadhorse and Kaktovik, which are located approximately 37, 44, and 14 km, respectively, from the closest Kulluk lease blocks, are shown in Table 4-2.

Table 4-2: Total Impacts at Nearest Communities (from Kulluk operations and including background concentrations)

Air Pollutant	Averaging Period	Total Impacts (μg/m^3) at			NAAQS (μg/m^3)
		Nuiqsut	Deadhorse	Kaktovik	
NO_2	1-hour	94	94	21	**188**
	Annual	11	11	1	**100**
$PM_{2.5}$	24-hour	17	17	7	**35**
	Annual	4	4	3	**15**
PM_{10}	24-hour	53	53	53	**150**
SO_2	1-hour	14	29	10	**196**

Exhibit 2

AR-EPA-H-1

EPA Region 10, Technical Support Document, Review of Shell's Ambient Air Quality Impact Analysis for the Kulluk OCS Permit Application, Permit No. R10OCS030000
(July 18, 2011)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
SEATTLE, WASHINGTON

TECHNICAL SUPPORT DOCUMENT
REVIEW OF SHELL'S
AMBIENT AIR QUALITY IMPACT ANALYSIS
FOR THE KULLUK OCS PERMIT APPLICATION
PERMIT NO. R10OCS030000

July 18, 2011

TABLE OF CONTENT

demonstrate compliance with the ozone, PM-2.5, NH_3 and reduced sulfur ambient air quality standards. Likewise the rules do not require minor permit applicants to demonstrate compliance with the "maximum allowable increases" (also known as PSD increments), or conduct any type of visibility impact analysis.

Shell provided an ambient demonstration for all pollutants triggered under the COA's minor permit program (NO_2, SO_2 and PM-10). While not required, they also submitted an ambient demonstration for the State of Alaska's NH_3 air quality standard.

C.2 Modeling Obligations under 40 CFR Part 71

As specified in 40 CFR § 55.13(f)(2), the requirements of Part 71 apply to OCS sources located beyond 25 miles of state's seaward boundaries. Since the potential to emit (PTE) for the project is greater than 100 tpy for several criteria pollutants, the Kulluk is classified as a Title V major source under Part 71.

Part 71 includes as "applicable requirements", "any national ambient air quality standard or increment or visibility requirement under part C of Title I of the Clean Air Act (Act), but only as it would apply to temporary sources permitted pursuant to section 504(e) of the Act." 40 CFR § 71.2. As discussed in the SOB, EPA believes the best interpretation of these provisions is that the NAAQS are applicable requirements for all Title V temporary sources, but that increment and visibility are applicable requirements only if such sources would otherwise be subject to PSD.

Part 71 does not specify how a Title V temporary source must demonstrate compliance with the NAAQS. In the absence of regulations or guidance setting out the requirements for a demonstration that the terms and conditions of a Title V permit for a Title V temporary source will assure compliance with NAAQS at all authorized locations of operation, Region 10 believes that following the regulations and guidance for conducting an air quality analysis with respect to the NAAQS under the PSD program is an appropriate approach. See 40 CFR Part 51, Appendix W.

The modeling analysis Shell submitted under the minor permit is consistent with PSD modeling requirements. Therefore, Shell's minor permit analysis meets the PSD NAAQS demonstration requirements for the pollutants triggered under the minor permit program. For the CO and PM-2.5 NAAQS, Shell submitted ambient demonstrations following the PSD demonstration requirements. Shell did not provide a modeling analysis for the Pb and ozone NAAQS.

Shell's decision to not provide a modeling analysis for Pb and ozone NAAQS is reasonable and supportable. It is reasonable because diesel-fired combustion units do not typically release substantive quantities of Pb and ozone-precursor emissions (volatile organic compounds or VOCs), and diesel fuel tanks do not emit large quantities of VOCs. Also, ensuring emissions of other pollutants, especially NO_2 and PM-2.5, do not cause or contribute to a violation of the NAAQS will provide similar assurance for Pb and ozone-precursor emissions for this type of source. Shell's decision is supportable because Pb and VOC emissions are below PSD significant emission rates for both pollutants. Shell's quantitative demonstration that they are complying with the NO_2 and PM-2.5 NAAQS is therefore sufficient for qualitatively demonstrating compliance with the Pb and ozone NAAQS. Additional information regarding ozone may be found in Section H of this TSD.

C.3 Modeling Obligations under 40 CFR Part 70

Shell's request for a Title V permit for continued operation within 25 miles of the seaward boundary did not trigger any ambient demonstration obligations not already triggered under the COA's minor permit program or Part 71.

C.4 Additional Discussion of Regulatory Obligations

For simplicity purposes, Region 10 intends to issue a single OCS permit that fulfills all three permitting mechanisms. This TSD therefore addresses Region 10's review of all ambient demonstration obligations, without further reference to the specific permit mechanism (e.g., COA minor permit program vs. Title V permit obligations).

D. Modeling Approach

A dispersion model is a computer simulation that uses mathematical equations to predict air pollution concentrations based on weather, topography, source characteristics and emissions data. Each of these aspects must be represented with numerical values that characterize the given features of the particular application and location.

Region 10 evaluated Shell's modeling analysis under the guidance established in 40 CFR Part 51, Appendix W, *Guideline on Air Quality Models* (Appendix W). The use of Appendix W for modeling analysis is required under the minor permit program, per 18 AAC 50.215(b). As discussed above, Region 10 believes it is appropriate to use Appendix W for assessing criteria pollutant modeling assessments required under Title V for Title V temporary sources. 40 CFR Part 51, Appendix W, Section 1.0(a).

D.1 Air Quality Model

As stated in Section 3.1 of Appendix W, EPA has developed models suitable for regulatory application. When a single model is found to perform better than others, it is recommended for application as a preferred model and listed in Appendix A of Appendix W. Shell employed the American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) system of programs to estimate their ambient impacts (EPA 2002).

Shell and Region10 started discussing refined modeling options for the Arctic marine environment in June 2010. The initial discussion focused on two preferred models for near-field applications: (1) the Offshore and Coastal Dispersion (OCD) model (DiCristofaro et al. 1989) and AERMOD, and (2) a non-guideline over water version of CALPUFF (BOEMRE 2006). Shell and Region 10 ultimately selected AERMOD after examining the capabilities of each model (EPA 04/01/11).

The AERMOD Modeling System consists of three basic modules: AERMAP (which is used to process terrain data and develop elevations for the receptor grid/sources), AERMET (which is used to process the meteorological data), and the AERMOD dispersion model (which is used to

G. Results and Discussion

The maximum modeled NO_2, SO_2, PM-10, PM-2.5, and CO impacts, background concentrations, total impacts, and NAAQS are summarized below in Table 11. All of the total impacts are less than the NAAQS. The modeling results show that the emissions associated with the proposed permit are not expected to cause or contribute to a violation of the NAAQS. The maximum 8-hour NH_3 impact is 6.6 μg/m^3 which is well below the State of Alaska air quality standard of 2,100 μg/m^3.

Table 11: Modeled Impacts at the Location of Maximum Impact

Air Pollutant	Averaging Period	Shell Only Impacts (without background) (μg/m^3)	Background Concentration (μg/m^3)	Total Impact Including Background (μg/m^3)	NAAQS (μg/m^3)	Total Impact as a % of NAAQS
NO_2	1-hour	110.6	40.9	**151.5**	188	81%
	Annual	4.4	11	**15.4**	100	15%
PM-2.5	24-hour	17.0	17	**34.0**	35	97%
	Annual	1.0	4	**5.0**	15	33%
PM-10	24-hour	20.8	53	**73.8**	150	49%
SO_2	1-hour	14.0	29	**43.0**	196	22%
	3-hour	8.9	29	**37.9**	1,300	3%
	24-hour	2.8	22	**24.8**	365	7%
	Annual	0.2	4	**4.2**	80	5%
CO	1-hour	1,268	1,742	**3,010**	40,000	8%
	8-hour	712	1,094	**1,806**	10,000	18%

H. Ozone

This section provides additional information regarding ozone and why Region 10 believes it is appropriate not to require a quantitative assessment that includes modeling for this pollutant. Ozone is inherently a regional pollutant, the result of chemical reactions between emissions from many sources over a period of hours or days, and over a large area. Ozone is formed in the atmosphere through a chemical reaction that includes NOx, VOC, and CO in the presence of sunlight. The sources of these air pollutants are mainly combustion sources such as power plants, refineries, and automobiles.

EPA does not have a recommended modeling approach for assessing the impact of an individual source on ozone. Individual source impacts are generally within the range of "noise" of regional ozone models (i.e., imprecision in predicted concentration due to uncertainty in model inputs for emissions, chemistry, and meteorology). Section 5.2.1(a) of Appendix W reflects this understanding: "Simulation of ozone formation and transport is a highly complex and resource intensive exercise." Paragraph (c) states: "Choice of methods used to assess the impact of an individual source depends on the nature of the source and its emissions. Thus, model users

Exhibit 3

AR-EPA-J-3

EPA Region 10, Response to Comments for Outer Continental Shelf Permit to Construct and Title V Operating Permit, Conical Drilling Unit Kulluk, Shell Offshore Inc. Beaufort Sea Exploration Drilling Program
Permit No. R10OCS030000
(Oct. 21, 2011)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION 10

SEATTLE, WASHINGTON

RESPONSE TO COMMENTS
FOR
OUTER CONTINENTAL SHELF
PERMIT TO CONSTRUCT AND
TITLE V AIR QUALITY OPERATING PERMIT
CONICAL DRILLING UNIT KULLUK

SHELL OFFSHORE INC.
BEAUFORT SEA EXPLORATION DRILLING PROGRAM
PERMIT NO. R10OCS030000

Table of Content

I. CATEGORY – ENFORCEABILITY OF PTE LIMITS

I.1 SUBCATEGORY – GENERAL

Comment I.1.a: Commenters request that Region 10 add to the list of "Prohibited Activities" the operation of the vessels between December 1 and June 30 because the Draft Permit specifies that the "permittee shall only conduct exploration drilling operations in the Beaufort Sea between July 1 and November 30 each year (referred to hereafter as the "drilling season")."

Response: The Kullulk Permit clearly states that "The permittee shall only conduct exploration drilling operations in the Beaufort Sea between July 1 and November 30 each year (referred to hereafter as the "drilling season")." Permit Condition D.3.1. This condition adequately prohibits operation of the Kulluk as an OCS source in the Beaufort Sea between December 1 and June 30 of each year, and the additional condition suggested by the commenters is not necessary.

Comment I.1.b: Commenters state that Region 10 fails to explain why monthly limits could not be imposed in the Draft Permit and why Shell was provided 12-month rolling emission limits for certain pollutants. The commenters reference EPA guidance providing that production and operational limits must be stated as conditions that can be enforced independently of one another and that EPA recommends a one month limit as the maximum time EPA should generally accept for avoiding a PSD threshold. The commenters also point to EPA guidance and state that Region 10 should first consider the possibility of imposing month-by-month limits, and only if that is not feasible should the Region impose a 12-month rolling time period. The commenters reference the following statement that they cite as originating from the Statement of Basis: "because the annual NAAQS are set based on calendar years, the restriction can similarly apply on a calendar year basis (or, in the case of these permits, a drilling season which is limited by the permit to a specific 5-month period out of any calendar year)." The commenters contend that this statement is misleading because it implies that Shell is complying with the NAAQS and other standards during the limited drilling season instead of taking a rolling 12-month timeframe in which to document compliance.

Response: Agency guidance provides that production or operational limits expressed on a calendar year basis cannot be considered capable of legally restricting potential to emit, and that such limits should generally not exceed one month, but can include longer rolling limits (*e.g.*, on a 12-month rolling basis). 1989 PTE Guidance at 10. This guidance applies to limiting a source's potential to emit and does not explicitly address limits established to protect the NAAQS. Region 10 believes that in this case limits imposed to ensure compliance with annual NAAQS standards can reasonably be expressed on a calendar year basis because compliance with the annual standard is determined based on calendar year or multi-year averages of calendar years.

The commenters' concern appears to relate to the fact that the Draft Permit includes PTE limits set on a rolling basis even though Shell is prohibited from operating under the permit between December 1 and June 30 of each year. The rolling PTE limits in Permit

Condition D.4 of the Draft Permit were established assuming zero emissions during the period when operations are prohibited (December through June of each year). In addition, each of the limits in the permit applies independently. In other words, even though the limits in Permit Condition D.4 could—on their own—allow the source to emit pollutants between December 1 and June 30 of each year, Permit Condition D.3.1 prohibits operation during that time period, and the permittee must comply with both requirements.

The commenters are correct that EPA guidance does express a general preference for shorter time periods rather than 12-month rolling limits. See 1989 PTE Guidance at 9. As the commenters acknowledge, however, EPA has also recognized that longer rolling limits are appropriate for sources with substantial and unpredictable annual variations in emissions, as well as for those sources that curtail operations during part of a year on a regular seasonal cycle. Id. at 9-10. Such is the case here. Shell's planned exploratory operations are atypical as compared to other sources because the emission units consist of multiple engines and generators with variable emissions on the Kulluk and a fleet of numerous support vessels. Operations will vary from hour-to-hour, day-to-day, month-to-month, and season-to-season based on factors such as the number of wells drilled, the activity being undertaken (drilling mud cellar lines, other drilling activity, or activity that does not involve drilling), the depth of the wells drilled, whether emergency engines are being run for testing, and ice conditions. Given the variability in operations, and thus emissions expected from this source, and after considering a full range of options for limiting the source's potential to emit, Region 10 determined that it was appropriate to establish longer-term rolling limits. In short, the Kulluk Permit does not set PTE limits on a calendar year basis, but instead establishes rolling 365-day limits for NO_x and CO, and 12-month rolling limits for SO_2 and GHG emissions. Region 10 determined that these limits are appropriate considering the nature of the source and are consistent with the 1989 PTE Guidance. See also response to comment I.1.c.

Similar to the 2011 Revised Permits for the Discoverer, the limit on the number of days in the drilling season in the Kulluk Permit is a limit set to ensure compliance with the annual NAAQS and therefore can reasonably be established, as was done here, on a calendar year (drilling season) basis. Region 10 also notes that the statement quoted by the commenters concerning setting annual NAAQS compliance limits on a calendar year basis is not contained in the Kulluk Statement of Basis. This statement is from the Supplemental Statement of Basis for the Discoverer Permits.

Comment I.1.c: Commenters contend that the owner-requested limits and other provisions designed to limit Shell's potential to emit are unenforceable as a practical matter and unlawful. Commenters note that absent enforceable permit limitations, Shell's yearly potential to emit exceeds the applicable major source threshold of 250 tpy for NO_x, CO, SO_2, and GHG emissions. The commenters reference that Shell's pre-permitted PTE for NOx is 2,339 tpy and that the Draft Permit limits NO_x emissions to 240 tpy determined on a rolling 365-day basis. Commenters further contend that although the Draft Permit describes how to calculate NO_x emissions it fails to specify how the emissions will be limited through an operational limit, a production limit, or the installation of controls or other mechanisms. As a result, the commenters state that the limit is not enforceable and fails to serve the intended purpose of restricting Shell's emissions of NO_x. The commenters assert that the same is true for potential to emit limits for CO and CO_2e.

Response: The commenters are correct that, absent enforceable permit limits, Shell's yearly potential to emit would exceed the applicable PSD major source thresholds for NO_x, CO, SO_2, and GHG emissions. See Statement of Basis, p. 24. Potential to emit is defined as the maximum capacity of a source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, is treated as part of its design if the limitation or the effect it would have on emissions is enforceable. See 40 CFR §§ 52.21(b)(4) and 55.2. Region 10 believes that the limits established in the Kulluk Permit to restrict the source's potential to emit are both federally enforceable and enforceable as a practical matter.

Title V of the CAA and Part 71 provide a mechanism to create limits in a Title V permit that restrict a source's potential to emit. The Environmental Appeals Board (EAB) has specifically acknowledged that "Title V permits (and other permits as well) may function as vehicles for establishing such PTE limits, potentially allowing a source to avoid more burdensome permitting requirements for 'major sources' by instead qualifying as a 'synthetic minor' source for purposes of some other regulatory programs." *In re Peabody Western Coal Company*, 12 EAD 22, 31 (EAB Feb. 18, 2000). Limits established in a Title V permit are federally enforceable. See 42 U.S.C. § 7661a, 40 CFR § 71.6(b), Permit Condition A.3.4. See also 18 AAC 50.225 (COA authority to impose owner-requested limits on PTE).

Region 10 determined that, given the variable nature of Shell's proposed operations and the number, types, and location of emission sources spread across the Kulluk and Associated Fleet, the most effective means to limit Shell's potential to emit was through the application of enforceable source-wide emission limits for NO_X, CO, SO_2 and CO2e. The proposed exploratory drilling operations will involve variable operations from well-to-well and season-to-season due to factors such as weather, sea state, remoteness of the drilling site, and the exploratory nature of the operations (i.e. the speculative nature of exploratory drilling). Emissions from many units will also vary depending on the activity being conducted. For example, emissions from drilling equipment on the Kulluk will depend on the stage of drilling activity (*e.g.*, drilling mud cellar lines versus other drilling activities), and emissions from the propulsion engines on the icebreakers will depend on the frequency, thickness, and location of ice. Such considerations require a level of operational flexibility that makes it impractical to establish unit-specific limits or operating parameters for some pollutants that might typically be applied to limit a stationary source's potential to emit. For these reasons, Region 10 determined that, for this permit, the most effective and reliable way to limit potential to emit was through a combination of emission limits and specified emission factors, supported by stringent monitoring, frequent emission calculations, recordkeeping requirements, and operating limitations. This approach accounts for variability in operations and emissions, yet still provides assurance that limits on potential to emit can be enforced as a practical matter.

The Kulluk Permit establishes an emission limit for SO_2 (10 tpy) that is well below the applicable PSD major source threshold as determined on a 12-month rolling basis. This emission limit is supported by operational limits on both the type and amount of fuel combusted that ensure emissions remain below the applicable emission limit. The permit restricts the sulfur content of fuel combusted on the Kulluk and Associated Fleet to 100 ppm. Permit Condition D.4.5. Compliance with this operational limit is determined by Permit Condition D.4.9 which requires that all fuel purchased have a maximum sulfur content of 15 ppm. The permit also establishes an aggregate fuel limit for all emission sources that limits the total amount of fuel combusted during any 12-month rolling period to 7,004,428 gallons. Permit Condition D.4.6. Compliance with the fuel limit is determined through stringent fuel monitoring requirements. For the majority of emission units, fuel usage is monitored continuously using a fuel flow meter. For the units where a fuel flow meter is not required (Kulluk emergency generator, seldom used sources, and OSRV work boats) the permit requires that fuel usage be measured using a fuel sight glass, tank gauge, or graduated dip stick. Under Permit Condition F.2.2.2. Shell is required to record fuel usage for each emission unit on an hourly, daily, and monthly basis. Permit Condition F.2.2. Together, the limits on the type and amount of fuel combusted, along with the fuel monitoring requirements, assure compliance with the emission limit for SO_2.

The Kulluk Permit establishes an emission limit for CO2e (80,000 tpy) below the threshold at which GHGs become “subject to regulation” for a new stationary source under the Tailoring Rule as determined on a 12-month rolling basis. This emission limit is supported by the operational limit on the amount of fuel combusted over a 12-month rolling period and an operational limit on the amount of waste combusted each day that, together, ensure emissions remain below the applicable emission limit, so the source’s GHG emissions are not “subject to regulation” for PSD permitting purposes and PSD permitting requirements do not apply. Permit Conditions D.4.6 and D.4.7. The permit requires Shell to monitor total fuel usage, as described above, and to monitor and record the operation of the incinerators on the Kulluk and Associated Fleet. Emissions are calculated by applying emission factors specified in Tables D.2.1 and D.2.2 to the amount of fuel combusted and the assumed maximum operation of the incinerators. Each month, Shell is required to calculate and record the rolling 12-month emissions of GHGs to ensure that emissions of CO2e remain below 80,000 tpy. For a discussion of methane emissions see response to comment I.3.b.

The Kulluk Permit establishes emission limits for NO_X (240 tpy) and CO (200 tpy) below the applicable PSD major source threshold, as determined on a rolling 365-day basis.
Compliance with the emission limits for NO_X and CO is determined by calculating daily NO_X and CO emissions from each emission unit using emission factors derived from stack testing conducted pursuant to specified requirements (Permit Condition E) or specifically identified in the permit (Permit Condition D.1). The permit requires Shell to

conduct stack tests for the majority of emission units to develop reliable emission factors for NO_X and CO. Stack testing is conducted across multiple load conditions for each emission unit or group of emission units. The highest emission factor determined through stack testing is used to calculate all emissions from the unit regardless of actual operating load conditions. For groups of the emission units, the highest emission factor observed for the group is used for all emission units in the group. For emission units that are not subject to stack testing for NO_X and CO (Kulluk emergency generator, seldom used sources, OSRV workboats, heaters and boilers), the permit specifies emission factors which are either the AP-42 emission factor or the 90^{th} percentile value derived from source tests of corresponding emission units on Shell's Discoverer drillship and Associated Fleet. For more discussion of emission factors see response to comment I.3.a.

Compliance with the emission limits for NO_X and CO is determined by applying the relevant emission factor to the amount of fuel combusted by each emission unit (or hours of operation for incinerators). The fuel monitoring requirements, described above, and the specified emission factors for individual emission units allow for source-wide emission calculations to be made. Shell is required to calculate and record on a weekly basis the daily emissions of NO_X and CO from each emission unit, and to calculate and record on a weekly basis the daily rolling 365-day emissions of NO_X and CO. In this way, Shell is required to provide a continuous assessment of daily NO_X and CO emissions to ensure that the source complies with its PTE limits. Determining NO_X and CO emissions from each unit on a daily basis provides a reliable and timely mechanism that will allow Shell to frequently assess compliance and to determine whether it is approaching the emission limits established to limit its potential to emit and to adjust its operations accordingly.

In addition to emission limits, the Kulluk Permit includes a combination of operational limits which effectively limit potential to emit as well. In addition to the limits on the type and amount of fuel combusted, the Kulluk Permit imposes hourly operational limits on MLC drilling and overall drilling activity. Permit Conditions D.3.3 and D.3.4. Shell is required to record the date and hour the Kulluk becomes an OCS Source and the date and hour of drilling and incineration activities. Permit Conditions D.3.6 to D.3.8. To limit emissions of NO_x and CO from larger emission units, the Kulluk Permit requires the installation and operation of add-on controls. Exhaust from emission units with the highest PTE for NO_x – the Kulluk electricity generation engines and the propulsion and generation engines on both icebreakers – will be directed to an operating selective catalytic reduction (SCR) control device that is evaluated at all times the affected source is operating using a continuous monitoring system (CMS). In addition, exhaust from the Kulluk electricity generation engines, MLC HPU engines, MLC air compressor engines, Kulluk deck cranes, and the propulsion and generation engines on both icebreakers are directed to an oxidation catalyst control device that controls combustible substances such as CO and PM and is evaluated using a CMS. Permit Conditions F.3 and F.4.

The 1989 PTE Guidance recognizes exceptions to the statement that emission limits alone are not generally sufficiently enforceable as a practical matter so as to limit PTE. While the situation presented by the Kulluk and Associated Fleet was not contemplated at the time the 1989 PTE Guidance was issued, Region 10 believes that this situation is sufficiently analogous to the rationale for recognizing the exception for the VOC surface coating. As in the case of VOC coating operations, the operational and production parameters for the emission units on the Kulluk and Associated Fleet are not readily limited due to the uniqueness of the source which includes a wide variety of emission units and varying emission factors for NOx and CO for the various emission units, resulting from the unpredictable nature and variability of operations, and the need for operational flexibility on fuel usage. Therefore, Region 10 has required the use of emission limits and specific emission factors based on conservative assumptions, coupled with a requirement to calculate hourly and/or daily emissions, to restrict potential to emit. In this way, the combination of emission limits and specified emission factors has an effect similar to operational limits because the operational parameters that are linked to the emissions are continuously tracked and used for compliance.

Region 10 believes the permit appropriately limits Shell's potential to emit in a manner that is both legally enforceable and enforceable as a practical matter. Moreover, Shell is aware that operations must be suspended when necessary to avoid exceeding the limits. In the unlikely event that PTE limits are exceeded, not only may Shell need to apply for and obtain a PSD permit, but it may be considered to have been in violation of PSD requirements from the time it was initially constructed.

I.2 SUBCATEGORY – APPROPRIATENESS OF EMISSION LIMITS

Comment I.2.a: Commenters cite to a letter from EPA Region 9 to the Nevada Division of Environmental Protection as support for the proposition that EPA's position is that a 5-10% buffer is appropriate for synthetic minor source air permits. The commenters apply the 5-10% buffer to the potential to emit NO_x under the Draft Permit and note that the 240 tpy emission limit provides less than a 5% buffer. The commenters assert that, at the very least, the final permit needs to provide a 5% buffer, but that given the unknowns associated with the Draft Permit and the Arctic conditions, Region 10 should ensure a 10% buffer for all owner requested restrictions.

Response: The letter cited by the commenters involved a revision to a Title V permit to allow the source to install and operate additional emission units that would have increased the source's potential to emit CO above the applicable major source threshold of 250 tpy. In the draft permit, the state permitting authority established a facility-wide emission limit for CO of 249 tpy, just below the major source threshold. Region 9 did not object to the emission limit, but encouraged the permitting authority to provide a larger buffer of between 5-10% in that case.

Congress established specific thresholds to determine when a source would be considered major for purposes of PSD review. 42 U.S.C. § 7479(1). Although establishing a 5-10% buffer where an emission limit is just below the major source threshold may increase confidence that a source will not exceed the applicable threshold, the commenter does not cite anything to suggest that this is a legal requirement.

Z. APPLICABILITY OF PSD INCREMENT AND VISIBILITY PROTECTION

Z.1 IN GENERAL

Comment Z.1.a: Although commenters support Region 10's determination that the Kulluk is a Title V temporary source, commenters state that the draft permit for the Kulluk is unlawful because it does not include conditions that will assure compliance with all applicable requirements of the CAA at all authorized locations. In particular, the commenters contend, Region 10 has failed to assess whether emissions from Shell's Kulluk operations will exceed applicable air increments. The commenters assert that, through the creation of limits called "increments," Congress designed the CAA not only to clean up dirty air but also to prevent the degradation of clean air. The commenters cite to language in CAA § 504(e) and similar language in 40 CFR Part 71 stating that no operating permit shall be issued to a temporary source "unless it includes conditions that will assure compliance with all the requirements of [the Clean Air Act] at all locations, including, but not limited to, ambient standards and compliance with any applicable increment or visibility requirements . . . ." The commenters continue that Region 10 has both identified an offshore "baseline area" to assess increments in the Chukchi and Beaufort Seas and identified a "minor source baseline date" (namely, July 31, 2009) for SO_2, NO_2, and PM. Because the minor source baseline date has passed, the commenters assert, the CAA "places strict limits on aggregate increases in pollution within the baseline area whether the increases come from minor or major sources," citing as support *Great Basin Mine Watch v. EPA*, 401 F.3d 1094, 1096 (9th Cir. 2005), *Reno-Sparks Indian Colony v. U.S. E.P.A.*, 336 F.3d 899, 903 (9th Cir. 2003), and 75 Fed. Reg. at 64,864, 64,868 (October 20, 2010)("After the minor source baseline date, any increase in actual emissions (from both major and minor sources) consumes the PSD increment for that area.")(parenthetical added for emphasis). The commenters state that increments are thus applicable to all sources—both major and minor. The commenters further assert that EPA's interpretation that a demonstration of compliance with increments is not required to issue Title V permits to temporary sources that are not PSD major source is inconsistent with the statutory language of CAA § 504(e), EPA's own Part 70 and Part 71 regulations, and the preamble to the Part 70 regulations. The commenters also state that Region 10 is only interpreting a part of the statutory language, therefore missing both the meaning and the intent behind the provision pertaining to temporary sources. Because Region 10 did not analyze Shell's compliance with applicable increments or impose permit conditions to ensure compliance with them, the commenters conclude, the draft permit does not ensure compliance with increments and the permit violates CAA § 504(e).

Response: EPA agrees with the commenters that all emission increases and decreases from both major and minor sources (with only a few exceptions provided for in the PSD statute[16]) occurring after the minor source baseline date is triggered, will consume or expand available increment. However, EPA does not agree that the CAA and regulations applicable in this instance require that Shell demonstrate that the Kulluk will not cause a

[16] See CAA § 163.

violation of the PSD increments in order to obtain the type of permit issued by EPA in this case.

The fact that minor source emissions consume increment does not necessarily mean that a minor source permit applicant is required to demonstrate that its proposed action will not cause or contribute to a violation of the increment to obtain a minor source construction permit. The criteria that must be met to obtain a minor source construction permit in this case are principally based on the terms of the minor source permitting program approved by Region 10 as part of the COA regulations. In this instance, the applicable Alaska regulations approved by EPA (18 Alaska Administrative Code (AAC) 50.502) do not require that a minor source permit applicant demonstrate that it will not cause or contribute to a violation of the PSD increment in order to obtain this type of permit.

The CAA and EPA regulations do not require that state minor source permitting programs contain criteria that require a minor source permit applicant to demonstrate that proposed construction will not cause a violation of a PSD increment. This is something states have the discretion to require, but is not a mandatory requirement under the provisions of the CAA or EPA regulations applicable to minor source permitting programs.

Section 110(a)(2)(C) of the CAA sets forth the basic requirement for preconstruction permits for both major and minor sources. Specifically, Section 110(a)(2)(C) states that the implementation plan shall:

> (C) include a program to provide for the …. regulation of the modification and construction of any stationary source within the areas covered by the plan as necessary to assure that national ambient air quality standards are achieved, including a permit program as required in parts C and D;

The permit program required in Part C of the CAA applies to major emitting facilities as defined in Section 169(1) of the CAA and the permit program required in Part D of the CAA applies to major stationary sources as defined in Section 302(j) of the CAA and in the various pollutant specific subparts of Part D. Only the major emitting facilities subject to the Part C permitting program (also referred to as the PSD permitting program) are expressly required under the CAA to demonstrate compliance with applicable PSD increments in order to obtain a permit to construct. See CAA § 165(a)(3)(A). New and modified stationary sources that are not major emitting facilities subject to the Part C permitting program are only required to demonstrate that the NAAQS will be achieved unless the applicable implementation plan provides otherwise. See CAA § 110(a)(2)(C); 40 CFR §§ 51.160(a)(2) and (b)(2).

For non-PSD sources, a state air quality management authority has a responsibility to ensure that its state implementation plan contains measures to prevent significant deterioration of air quality in accordance with section 161 of the CAA and 40 CFR §§ 51.166(a)(1) of EPA's implementing regulations. However, these provisions leave states with the discretion to determine whether it is necessary to require minor sources to demonstrate that they will not cause a violation of any PSD increments as a condition of obtaining a minor source permit. In this instance, Alaska has not adopted minor source permit program regulations that require a showing that a minor source will not cause a violation of an increment in order to obtain the appropriate construction permit. Thus, the minor source COA regulations applicable to this source do not require a source to demonstrate compliance with PSD increments.

Furthermore, as discussed in the Statement of Basis (at 26), EPA does not interpret CAA § 504(e) to create new permitting requirements for temporary sources with respect to demonstrating compliance with increments beyond what would otherwise be applicable to such sources under applicable CAA construction permitting programs. The statute states in relevant part that:

> The permitting authority may issue a single permit authorizing emissions from similar operations at multiple temporary locations. No such permit shall be issued unless it includes conditions that will assure compliance with all applicable requirements of this chapter at all authorized locations, *including but not limited to ambient standards and compliance with <u>any applicable</u> increment or visibility requirements under part C of subchapter I of this chapter*.

CAA § 504(e) (emphasis added).

The difference in phrasing here is important: ambient standards are referenced without qualification, whereas increment and visibility requirements are prefaced with "any applicable" and followed by "under part C of subchapter I of this chapter." Based on this distinction, EPA reads this provision of the Clean Air Act to require that all Title V temporary sources[17] demonstrate that the source will not violate ambient standards (NAAQS) at all authorized locations but that such a source need only assure compliance with increment at all locations where the source is otherwise required to show it will not cause of violation of increments under part C of subchapter I of this chapter, such as through section 165(a)(3) of the CAA and the applicable PSD permitting program in the case of major sources or other provisions in an implementation plan or COA regulation that implement Section 161 of the Act and may also apply to minor sources.

The language used in Section 504(e) is consistent with the provisions in the CAA and EPA's regulations described above that make the ambient standards (the NAAQS) applicable to all stationary sources (both minor and major) at the time of construction permitting, but that make the increment requirements in Part C only applicable to certain stationary sources, that is PSD major sources or minor sources when applicable under an applicable minor source permitting program. This reading of the statute gives meaning to the different language that Congress used when referring to the ambient standards on the one hand and the Part C requirements for increments on the other hand.

[17] This term includes any source that would move more than once during the life of its Title V operating permit. See Memorandum to Docket A-90-33, re: Docketing of Detailed Responses to Comments on the Part 70 Operating Permit Regulations, at 6-34. It thus includes both PSD portable sources and PSD temporary sources.

Similarly, there is no indication in EPA's promulgation of the regulations implementing Section 504(e) that EPA interpreted that section of the CAA to impose on Title V temporary sources that are not also PSD major sources a direct requirement to demonstrate compliance with increment in the Title V permitting process. The thirteenth item in EPA's definition of "applicable requirement" in the Part 70 or Part 71 Title V regulations reads as follows: "Any national ambient air quality standard or increment or visibility requirement under part C of title I of the Act, but only as it would apply to temporary sources permitted pursuant to section 504(e) of the Act." 40 CFR § 70.2; 40 CFR § 71.2. The last clause makes clear that the NAAQS, increment, and visibility requirements are applicable requirements for Title V applicants only to the extent required under section 504(e) of the Act. Thus, this provision of the regulations was clearly not intended to require more than the cited provision of the Clean Air Act would otherwise require. As discussed above, because the reference to the increment in section 504(e) of the CAA is modified by the phrase "any applicable," the regulatory language EPA adopted in section 71.2 is likewise limited to requiring a Title V temporary source to demonstrate compliance with the increment where otherwise applicable under construction permitting programs.

Comment Z.1.b: Commenters state that, in the Statement of Basis (at 25), Region 10 attempts to justify its wholesale failure to address compliance with increments by suggesting that they are applicable only where a source "would otherwise be subject to PSD" and that Region 10 bases this conclusion on the observation that the word "applicable" precedes "increment" in CAA § 504(e). The commenters assert that this interpretation is wrong as a matter of law because, once triggered by a major source permit application in an area, increment limits apply to both major and minor sources. The commenters contend that Section 504(e) does not create a different rule for Title V temporary sources and, indeed, states that a Title V permit shall not be issued to a temporary source "unless it includes conditions that will assure compliance with all the requirements" of the CAA. The commenters state that the term "applicable" as used in CAA § 504(e) is not a reference to the applicability of general PSD requirements to a particular source, but rather refers to whether a major source application has triggered increment requirements for the relevant baseline area within which the temporary source is expected to operate and thus made such requirements "applicable." As support, the commenters state that, in promulgating its Title V implementing regulations, EPA declared that "NAAQS and the increment and visibility requirements under part C of title I of the Act are applicable requirements for temporary sources . . . ." Because in this case, previous major source applications have triggered the increment requirements in the area, the commenters state that Region 10 must ensure that the permit meets those requirements.

Response: EPA agrees that, once a minor source baseline date is triggered, emission increases and decreases of all sources, including minor sources after the minor source baseline date, will consume or expand increment. However, the increments themselves are not directly applicable as permitting criteria for sources that are not otherwise required to demonstrate compliance with increments to obtain a construction permit. As discussed above the state air quality management authority is required under Section 161 of the CAA and 40 CFR §§ 51.166(a)(1) of EPA's implementing regulations to adopt measures in its SIP to prevent significant deterioration. States have the discretion to determine the types of measures that are needed to meet this objective and are not expressly required to mandate that minor sources demonstrate they will not cause a violation of an increment to obtain a construction permit. When an air pollution authority finds that these measures have not been successful and an increment violation has occurred, it must revise its SIP to adopt emission limitations or other control measures to remedy the violation. 40 CFR § 51.166(a)(3).

As discussed in the response to comment Z.1.a above, EPA does not interpret section 504(e) and EPA's Part 71 regulations to require non-PSD sources to demonstrate compliance with increments in order to get a Part 71 operating permit when the applicable state or federal implementation plan does not otherwise require such a demonstration. The commenter quotes the thirteenth item in the definition of applicable requirement, but neglects to reference the last clause of this provision, which reads as follows "but only as it would apply to temporary sources permitted pursuant to section 504(e) of the Act." As discussed above, this clause indicates that EPA's regulations do not create any additional requirements for stationary sources beyond what the Act would require. Thus, EPA is not persuaded by commenter that the "any applicable" language that precedes the reference to increments is only intended to reference circumstances when a major source permit application has triggered increment requirements in a baseline area.

If, at any time after the Kulluk begins operation under its Title V/OCS permit, Region 10 determines that the actual emissions increases from the permitted OCS source cause or contribute to an increment violation,[18] Region 10 has authority to adopt additional requirements to ensure that increments are not violated. See CAA §§ 301 and 328; 40 CFR § 55.13(h). However, as shown in the Technical Support Document (Table 11, at 33) and confirmed by the comments of the North Slope commenters' (see Table 3 at page 13), the modeling analysis for this project shows that the allowable emissions would not cause or contribute to a violation of any increment where the minor source baseline has already been triggered. And, as discussed below in the response to comment Z.2.a, $PM_{2.5}$ emissions from the Kulluk will be part of the baseline concentration and will not consume any of the available $PM_{2.5}$ increment. So, although EPA does not believe that CAA § 504(e) and 40 CFR Part 71 require a demonstration of compliance with increments in this Title V permit issuance process, the modeling analysis supporting this permit actually demonstrates that PSD increments will not be violated.

Comment Z.1.c: Commenters state that EPA's regulations fail to support the interpretation that increment and visibility are not "applicable requirements" for minor sources under CAA § 504(e) and 40 CFR Part 71. According to the commenters, EPA's regulations explain that "[p]ermits for temporary sources shall include the following: (1) Conditions that will assure compliance with all applicable requirements at all authorized

[18] 40 CFR § 52.21(b)(13) (definition of "baseline concentration" is in terms of actual emission increases and decreases).

locations ....," citing to 40 CFR § 71.6(e). The commenters continue that the Part 71 regulations also include a definition of "applicable requirement" that includes thirteen requirements, including "(2) Any terms or condition of the preconstruction permits issued pursuant to regulations approved or promulgated through rulemaking under title I, including parts C and D, of the Act" and "(13) Any national ambient air quality standard or increment or visibility requirement under part C of title I of the Act, but only as it would apply to temporary sources permitted pursuant to section 504(e) of the Act," citing to 40 CFR § 71.2 (definition of applicable requirement). The commenters contend that EPA's interpretation of this definition reads the thirteenth requirement out of the regulations because, under Region 10's interpretation, the thirteenth requirement is subsumed by the second requirement. Thus, the commenters conclude, an interpretation that requires temporary sources to comply with the NAAQS, increments, and visibility standards is the only reading that gives meaning to all the regulatory provisions in the definition of applicable requirement. Commenters also cite to language in the in the preamble to the final Part 70 rule which states that "Temporary sources must comply with these requirements because the SIP is unlikely to have performed an attainment demonstration on a temporary source."

Response: EPA disagrees with the commenter's assertion that its interpretation of the thirteenth requirement does not give meaning to all of the regulatory provisions in the definition of "applicable requirement." The commenters argue that EPA's interpretation would be subsumed by the second requirement – that the permit include the terms and conditions of any preconstruction permit. However, the commenter fails to recognize that the permit for a portable (temporary) source that would be issued pursuant to the PSD regulations, specifically 40 CFR § 52.21(i)(1)(viii), is not required to assure compliance with the NAAQS or increments at all future locations. Rather, the PSD permit must only ensure that, at future locations, emissions from the permitted source would not impact a Class I area or an area where the increment is known to be violated. The PSD permit for a portable source would not thus not be required to ensure that the PSD portable source would not cause a new increment violation at a future location or that it would not have a local visibility impact at a future location. So while EPA's interpretation is that Title V temporary sources that are not PSD sources do not need to demonstrate compliance with PSD increments and visibility requirements unless otherwise required by the applicable implementation plan, Region 10's interpretation does result in the imposition through the Title V permit of additional requirements on PSD sources beyond the conditions that would be included in a PSD preconstruction permit under 40 CFR § 52.21. Region 10's interpretation thus maintains the basic premise of the CAA preconstruction programs—that PSD major sources are subject to NAAQS and increment in the permitting process, where as non-PSD sources are subject only to the NAAQS unless the applicable minor source program also includes the increment—yet still has meaning by imposing on Title V temporary sources the requirement to demonstrate at subsequent locations that they continue to comply with those underlying applicable preconstruction requirements at each subsequent location.

With respect to the language in the preamble to the final Part 70 rule cited by the commenters with respect to Title V temporary sources, there is nothing in that language to suggest that EPA interpreted Section 504(e) of the Clean Air Act to change the basic premise of the Clean Air Act permitting scheme for PSD sources versus non-PSD sources, namely, that PSD sources are directly subject to NAAQS and increment requirements, whereas non-PSD sources are not required to show they will not cause a violation of the increment unless the applicable implementation plan otherwise requires it for such sources. If a non-PSD Title V source applied for a preconstruction permit at one location and then applied for a new preconstruction permit to move to a new location, the source would have to demonstrate compliance with the NAAQS at each location as a condition of obtaining a permit, but would not have to demonstrate compliance with increment at either location absent a similar requirement for minor sources in the applicable implementation plan. In contrast, a PSD source that applied for a preconstruction permit at one location and then applied for a new preconstruction permit to move to a new location would have to demonstrate compliance with the NAAQS and increment at both locations. EPA believes the intent of the Title V temporary source provisions is to relieve sources of the burden of applying for Title V permits for each new location, while at the same time, assuring compliance with all requirements to which the source would be subject if it were a new source at each such new location.

Comment Z.1.d: Commenters assert that, in light of the statutory and regulatory language and the special treatment given to temporary sources in the 1990 amendments to the Clean Air Act, it is appropriate that compliance with both the increments and visibility requirements is ensured for these permits. The commenters state that this is particularly critical because of the proximity of these operations to the Arctic National Wildlife Refuge, (ANWR) and that the OCS regulations provide that EPA "shall not issue a permit to operate to any existing OCS source that has not demonstrated compliance with all applicable requirements of this part."

Response: See the response to comments Z.1.a-Z.1.c above in general with respect to the applicability of increments to Title V temporary sources that are not PSD major sources. EPA has determined that visibility is similarly not an applicable requirement for Title V temporary sources that are not PSD major sources for the reasons set for in the Statement of Basis and response to comments Z.1.a-Z.1.c. In addition, ANWR is not a federal Class I area and as such, the increment and visibility requirements of Part C that apply to federal Class I areas are not relevant for ANWR.

Comment Z.1.e: Commenters state that EPA's regulations for SIPs provide that "[in accordance with the policy of Section 101(b)(1) of the CAA and for the purposes of section 160 of the Act, each applicable State Implementation Plan and each applicable Tribal Implementation Plan shall contain emission limitations and such other measures as may be necessary to prevent significant deterioration of air quality." 40 CFR § 51.166(a). This regulatory provision, the commenters continue, supports the need for the SIP to protect increments. Therefore, the commenters contend, even though the SIP would not have accounted for the temporary sources in assuring protection of the increments, any Title V temporary source permitted under Part 71 must demonstrate compliance with the increments in order to ensure all SIP requirements are met. Commenters contend that the Part 70 regulations pertain to State Implementation Plans and that the oil and gas companies have advocated that such requirements only apply in the inner OCS *(i.e.*, within 25 miles of the State's seaward boundary). The commenters assert, however, that CAA § 328 makes it clear that EPA "shall establish requirements to control air pollution from Outer Continental Shelf sources located offshore ... to attain and maintain Federal and State ambient air quality standards and to comply with the provisions of' the PSD program." The commenters therefore assert that, because the goal of CAA § 328 is attainment of air quality standards, it matters little whether the source is located on the inner or outer OCS, because in both cases the relevant SIP will not have performed an attainment demonstration for such sources. Because the preamble to the Part 71 regulations relies upon the reasoning put forth by EPA in developing the Part 70 regulations, especially in discussing applicable requirements, the statutory and regulatory language for Part 70, as well as EPA's regulatory preambles, all support a finding that the NAAQS, increments, and visibility requirements are all applicable to temporary OCS sources under Part 71.

Response: See the other responses to comments in this Subcategory Z.1 with respect to the applicability of increments and visibility requirements to Title V temporary sources that are not subject to PSD permitting. Region 10 agrees that, in general, there is no intention for the Part 71 federal operating permit program that applies on the outer OCS to be different from the onshore Part 70 operating permit program that Region 10 has incorporated by reference in the COA regulations for application in the inner OCS (the only differences would be the result of differences between the State adopted program and EPA's Part 71 regulations). In this case, the requirements for Title V temporary sources in the inner OCS and outer OCS off of Alaska are the same because Alaska has adopted EPA's Part 71 rules with respect to Title V temporary sources by reference for application onshore and Region 10 has in turn adopted these requirements into the COA regulations for application in the inner OCS.

Region 10 does not agree with the rationale put forth by the commenters, however, that in both cases the relevant SIP will not have performed an attainment demonstration because there is no SIP (or implementation plan equivalent) for the outer OCS. Section 328 does not require EPA to establish an implementation plan or other comprehensive air quality management program for the outer OCS. It only requires EPA to adopt regulations for OCS sources and even then, only for certain purposes. Nonetheless, as discussed in response to comment Z.1.e, EPA does have authority to address violations of increment on the inner and outer OCS.

Z.2 SUBCATEGORY – $PM_{2.5}$ INCREMENT

Comment Z.2.a: Commenters state that the Kulluk operations, as proposed, do not comply with the 24-hour average Class II PSD increment for $PM_{2.5}$. Commenters note that on October 20, 2010, EPA adopted a final regulation that went into effect on December 20, 2010 and that establish new PSD increments for $PM_{2.5}$ that went into effect on October 20, 2011. The commenters assert that Section 328 states that "[n]ew OCS sources shall comply with such requirements on the date of promulgation," citing to CAA § 328. The commenters state that, as a "new OCS source" yet to commence operation,

Exhibit 4

AR-EPA-B-30

Alaska Department of Environmental Conservation (ADEC), Air Permits Program, Technical Analysis Report for Air Quality Control Minor Permit No. AQ0181MSS04, BP Exploration (Alaska) Inc. (BPXA), Endicott Production Facility
(Mar. 30, 2009)

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

Preparer: Patrick Dunn
Supervisor: Sally A. Ryan, P.E.
Date: Final – March 03, 2009

\\jn-svrfile\Statewide Allshare\Groups on Juneau\AQ\PERMITS\AIRFACS\BPXA\Endicott\Minor\MSS04 - Drill Rig and Permit Hygiene\Final\181MSS04 Final TAR.doc

TABLE OF CONTENTS

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 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

Exhibit 5

AR-EPA-B-31

ADEC, Air Permits Program, Technical Analysis Report, Air Quality Control Minor Permit No. AQ0166CPT04, BP Exploration (Alaska) Inc., Central Compressor Plant (CCP) and Air Quality Control Construction Permit AQ0270CPT04, BP Exploration (Alaska) Inc., Central Gas Facility (CGF)
(Oct. 13, 2009)

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
Supervisor: Sally A. Ryan
Final – October 13, 2009

TABLE OF CONTENTS

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.

- 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.

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 µg/m^3. The Department found that the reported 3-hour and annual average ppm values contain typographical errors. However, the reported µg/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.

<u>Discussion re Land-Sea Breeze Affects</u>

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.

Horizontal/Capped Stacks

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.

Stack Dimensions

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 <u>not</u> 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

Exhibit 6

AR-EPA-I-8

EPA Region 10, Statement of Basis for Proposed Outer Continental Shelf Prevention of Significant Deterioration Permit No. R10OCS/PSD-AK-09-01, Shell Gulf of Mexico Inc., Frontier Discoverer Drillship, Beaufort Sea Exploration Drilling Program
(Feb. 17, 2010)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
SEATTLE, WASHINGTON

STATEMENT OF BASIS
FOR PROPOSED
OUTER CONTINENTAL SHELF
PREVENTION OF SIGNIFICANT DETERIORATION
PERMIT NO. R10OCS/PSD-AK-2010-01

SHELL OFFSHORE INC.
FRONTIER DISCOVERER DRILLSHIP
BEAUFORT SEA EXPLORATION DRILLING PROGRAM

Date of Proposed Permit: February 17, 2010

TABLE OF CONTENT

ambient air quality for that pollutant in the area. In addition, 40 C.F.R. § 52.21(m)(2) authorizes EPA to require post-construction ambient air quality monitoring if EPA determines it is necessary to determine the effect that emissions from the source or modification may have on air quality.

40 C.F.R. § 52.21(o) requires an additional impact analyses, which must include an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the proposed source or modification, or that would occur as a result of any commercial, residential, industrial and other growth associated with the source or modification. Analysis for vegetation having no significant commercial or recreational value is not required.

For sources impacting Federal Class I areas, 40 C.F.R.§ 52.21(p) requires EPA to consider any demonstration by the Federal Land Manager that emissions from the proposed source modification would have an adverse impact on air quality related values, including visibility impairment. If EPA concurs with the demonstration, the rules require that EPA shall not issue the PSD permit.

5.2 Class II PSD Increments and NAAQS

5.2.1 PSD Baseline Dates

Figure 2-1 shows the location of the Shell Beaufort Sea lease blocks relative to the northern Alaska coastline. For sources locating on the OCS more than 25 miles from the State's seaward boundary (the Outer OCS), EPA considers the "baseline area" for purposes of 40 C.F.R. § 52.21 to be the area bounded on the shoreward side by a parallel line 25 miles from the State's seaward boundary; on the seaward side by the boundary of U.S. territorial waters; and on the other two sides by the seaward extension of the onshore Air Quality Control Region (AQCR) boundaries (EPA 07/02/09 Baseline Memo). OCS sources within 25 miles from the State's seaward boundary (the Inner OCS) are subject to the COA PSD regulations, including the minor source baseline dates established for the COA, so defining a "baseline area" for the Inner OCS is unnecessary. Effectively, those portions of the Beaufort Sea encompassing the Inner OCS and the Outer OCS are separate baseline areas with different minor source baseline dates.

The major stationary source baseline date, as defined in 40 C.F.R. § 52.21(b)(14)(i), and the trigger dates for SO_2, NO_2, and PM_{10} for this baseline area are shown in Table 5.1.

Table 5-1: Major Source Baseline Dates

Air Pollutant	Major Stationary Source	Trigger Date
Sulfur Dioxide	June 5, 1975	August 7, 1977
Nitrogen Dioxide	February 8, 1988	February 8, 2008
Particulate Matter	June 5, 1975	August 7, 1977

The minor source baseline date is established in an area when the first complete PSD application is submitted to EPA after the trigger date. See 40 C.F.R. § 52.21(b)(14)(i). EPA deemed the

Shell OCS/PSD application for exploratory drilling in the Chukchi Sea complete on July 31, 2009 (EPA 07/31/09 Completeness Letter), which effectively establishes July 31, 2009 as the minor source baseline date for SO_2, NO_2, and PM_{10} in the Chukchi Sea/Beaufort Sea Outer OCS baseline area. As a result, Shell is required to consider increment consuming emissions increases and decreases after July 31, 2009 from other sources in the area in its analysis of compliance with air quality increments. Due to the size of the AQCR and the location of the Shell Chukchi Sea drilling area relative to the Beaufort drilling area, emissions from the Chukchi project are not expected to have a significant impact at the Shell Beaufort Sea drilling area. Since the minor source baseline dates of the corresponding shore area apply in the Inner OCS, additional increment-consuming sources are required to be considered for modeled receptor locations in the Inner OCS. The minor source baseline dates have been triggered in this AQCR as shown in Table 5.2 below (Schuler 07/02/09). Shell disagrees with EPA's interpretation of this point, but included existing onshore sources within 100 kilometers of Shell's lease blocks in its PSD increment analysis. (Shell Beaufort Permit Application 01/18/10, Section 3.3.3)

Table 5-2: Minor Baseline Dates

Air Pollutant	Minor Source Baseline Date Beyond 25 Miles from the State Seaward Boundary	Minor Source Baseline Date Onshore and Within 25 Miles from the State Seaward Boundary
Nitrogen Dioxide	July 31, 2009	February 8, 1988
Particulate Matter	July 31, 2009	November 13, 1978
Sulfur Dioxide	July 31, 2009	June 1, 1979

Shell anticipates constructing a warehouse on shore which would have an oil fired heater in the existing Northern Alaska Intrastate AQCR. The PSD analysis of this source would be based on the onshore minor source baseline dates.

5.2.2 PSD Significant Impact Analysis

The PSD air quality analysis for Shell's exploratory drilling program was conducted in two basic stages. First, Shell conducted a screening analysis to determine the pollutants for which the project exceeded the significant impact levels and for which a more robust air quality demonstration would be required. Second, where the predicted maximum concentration of the specific air pollutant was greater than the applicable significant impact level, a full PSD increment and NAAQS analysis was performed for the pollutant. EPA guidance calls for a more detailed air quality analysis if the emission rate of a pollutant is significant, and if the predicted maximum ambient air concentration of the specific air pollutant is greater than the applicable significant impact level. (See e.g. EPA 10/90 Draft NSR Manual) As shown in Table 5-3, the highest concentration impact from the Discoverer and the Associated Fleet predicted by the screening analysis for the applicable averaging time exceeded the significant impact levels for NO_2 and PM_{10}. As a result, a detailed ambient air quality impact analysis is required for these air

Table 5-8: Onshore Facilities

		Facility Wide Emissions (tpy)		
Company	**Facility**	**NO_X**	**SO_2**	**PM_{10}**
BP	Badami	277.9	66.6	11.6
BP	Base Operations Center	1165.0	171.0	37.0
BP	Central Compression Plant	14238.0	147.0	347.0
BP	Central Gas Facility	10968.0	125.0	305.0
BP	Endicott Production Facility[1]	3594.0	539.0	63.0
BP	Flow Station #1	2872.0	35.0	84.0
BP	Flow Station #2	3663.0	83.0	91.0
BP	Flow Station #3	4235.0	42.0	100.0
BP	Gathering Center #1	4912.0	48.0	107.0
BP	Gathering Center #2	2370.0	38.0	84.0
BP	Gathering Center #3	2873.0	33.0	69.0
BP	Lisburne Production Center	2241.0	263.0	57.0
BP	Northstar Production Facility	562.0	56.5	331.0
BP	PBU Central Power Station	6110.0	63.0	150.0
BP	Prudhoe Bay Operations Center	231.0	51.5	45.8
BP	Seawater Injection Plant East	2175.0	20.0	42.0
BP	Seawater Treatment Plant	395.0	28.0	35.0
BP	Transportable Drilling Rigs	1386.7	145.6	56.7
Alyeska	TAPS Pump Station 001	773.0	39.0	122.0
Alaska Interstate	Deadhorse Soil Remediation Unit	107.0	162.8	13.5
Haliburton	Deadhorse Facility	249.0	1.5	2.3
TDX	Deadhorse Power Plant	246.0	9.0	17.0
Total		**65644.0**	**21683.0**	**2171.0**

Reference: Shell Beaufort Permit Application 01/18/10
[1] Endicott Production Facility emissions include the Liberty Expansion

Exhibit 7

AR-EPA-BB-34

Memorandum from D. Bray, Senior-Policy Advisor, U.S. EPA, to R. Albright, Director, Office of Air, Waste, and Toxics, U.S. EPA
(July 2, 2009)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue, Suite 900
Seattle, Washington 98101-3140

July 2, 2009

Reply To: AWT-107

MEMORANDUM

SUBJECT: Implementing PSD Baseline Dates, Baseline Areas, and Baseline Concentrations on the Outer Continental Shelf in Alaska

FROM: David C. Bray DCB
Senior Policy Advisor

TO: Rick Albright, Director
Office of Air, Waste, and Toxics

Janis Hastings, Associate Director
Office of Air, Waste, and Toxics

Introduction

The purpose of this memorandum is to clarify how EPA Region 10 intends to implement the PSD increments on the OCS in Alaska the absence of formal area designations under section 107(d).

Background

Pursuant to Section 328 of the Clean Air Act (Act) EPA has promulgated regulations to control air pollution from Outer Continental Shelf (OCS) sources to attain and maintain Federal and State ambient air quality standards and to comply with the provisions of Part C of title I (prevention of significant deterioration of air quality or PSD). See 40 CFR Part 55.

In Part C of Title I of the Act, Congress sets forth a program for preventing significant deterioration of air quality in areas that have air quality better than the National Ambient Air Quality Standards (NAAQS). Specifically, Congress established an approach for defining "significant deterioration" that relies upon changes in air quality concentrations from a baseline. The "baseline concentration" is defined in section 169(4) of the Act and the acceptable changes in concentration, called "increments," are defined in sections 163 (for Congressionally-established increments) and 166 (for EPA-established increments) of the Act.

Under Section 169(4) of the Act, the term "baseline concentration" means, "with respect to a pollutant, the ambient concentration levels which exist *at the time of the first application for a permit in an area subject to this part*, based on air quality data available in the Environmental Protection Agency or a State air pollution control agency and on such monitoring data as the permit applicant is required to submit. Such ambient concentration levels shall take into account all projected emissions in, or which may affect, such area from any major emitting facility on which construction commenced prior to January 6, 1975, but which has not begun operation by the date of the baseline air quality concentrations determination. Emissions of sulfur oxides and particulate matter from any major emitting facility on which construction commenced after January 6, 1975, shall not be included in the baseline and shall be counted against the maximum allowable increases in pollutant concentrations established under this part." (emphasis added). EPA has promulgated regulatory definitions for the phrases "the time of the first application for a permit" (known as the "minor source baseline date") and "in an area subject to this part" (known as the "baseline area"). These definitions are found in 40 CFR 52.21(b) of EPA's regulations and incorporated into the OCS regulations at 40 CFR 55.13.

The requirements to which OCS sources are subject depend on the distance of the source from shore. From the State's seaward boundary (typically 3 miles from shore) and extending out 25 miles, the requirements for the Corresponding Onshore Area (COA), as well as federal requirements, apply to OCS sources; beyond 25 miles from the State's seaward boundary, only federal requirements apply. See 40 CFR 55.3(b) and (c). Because of these different regulatory requirements, the implementation of PSD increments is different in these two portions of the OCS.

<u>Sources located less than 25 miles from the State's seaward boundary</u>

In accordance with section 328 of the Act and EPA's implementing regulations at 40 CFR Part 55, an OCS source located less than 25 miles from the State's seaward boundary is subject to the same requirements as would be applicable if the source were located within the COA. Section 328(a) of the Act; 40 CFR 55.3(b). As a result, EPA incorporates by reference the air quality regulations, including the major source permitting programs, that are in effect in the COA and applies them to OCS sources inside this 25 miles limit. See 40 CFR 55.12. The OCS rules define the term "onshore area" in terms of the section 107(d) area designations. 40 CFR 55.2. Hence the COA is generally synonymous with a section 107(d) area and, if designated attainment or unclassifiable, with a PSD baseline area.

Since the COA PSD rules look to the designation of the COA for determining baseline dates, applying the COA PSD rule to an OCS source includes using the COA minor source baseline dates. Importantly, the minor source baseline dates for a section 107(d) area are not established in regulation, but rather they are determined through the implementation of the PSD regulations. See 40 CFR 52.21(b)(definition of "minor source baseline date"). Where the COA PSD rules apply on the OCS, the baseline date that has already been determined under the COA rule is the baseline date that applies for the permitting of the OCS source. This baseline date is then used to determine the baseline concentration in the area of the OCS source in accordance with the COA PSD rules.

When using the onshore minor source baseline date for OCS sources located less than 25 miles from the State's seaward boundary, there is no need to define separate baseline areas (and hence section 107 area designations) for the OCS source. In fact, establishing this portion of the OCS as a separate baseline area, or extending the onshore baseline area onto the OCS, would be contrary to the current Part 55 rules which require a case-by-case determination of the COA for the purpose of determining the applicable onshore rules. See 40 CFR 55.5. Since the COA may be different than the nearest onshore area (NOA), and can actually differ from permit to permit, the applicable permitting rules, and hence the baseline date, could be different than that of the NOA. As such, a fixed baseline area for the OCS within 25 miles of the State's seaward boundary could potentially prevent the utilization of the COA minor source baseline date, contrary to the intent of Congress that such sources be subject to the same requirements as would be applicable if the sources were located within the COA.

Sources located more than 25 miles beyond the State's seaward boundary

For sources locating on the OCS more than 25 miles from the State's seaward boundary, the EPA PSD rules at 40 CFR 52.21 apply. The definition of "baseline area" in the federal PSD rules relies on the existence of intrastate areas designated as attainment or unclassifiable under section 107(d) of the Act. See 40 CFR 52.21(b). Until EPA either designates section 107(d) areas on the OCS and/or promulgates revisions to the definition of "baseline area" in 40 CFR Part 55, it is appropriate to implement the term "baseline area" in 40 CFR 52.21(b), for OCS areas more than 25 miles from the State's seaward boundary by using the boundaries of the coastal Air Quality Control Regions on shore as a guide. Accordingly, the following areas will be considered as separate "baseline areas" for purposes of 40 CFR 52.21:

> Each area bounded on the shoreward side by a parallel line 25 miles from the State's seaward boundary; on the seaward side by the boundary of U.S. territorial waters; and on the other two sides by the seaward extensions of the onshore Air Quality Control Region boundaries.

This approach is consistent with the approach of the Clean Air Act and EPA's implementing regulations for defining baseline areas on shore. Section 107 of the Act sets forth the criteria and processes for defining Air Quality Control Regions (AQCR's) and attainment/nonattainment designations. AQCR's for all States have been promulgated by EPA in 40 CFR Part 81, Subpart B. States are required, under section 107(d) to submit to the Administrator recommendations for attainment/nonattainment designations for (air quality control) regions or portions thereof. The final attainment/nonattainment designations for each State have been promulgated by EPA in 40 CFR Part 81, Subpart C. Under this statutory scheme, the largest possible onshore PSD baseline area is an AQCR. See Section 107(d) of the Act and 40 CFR 52.21(b)(definition of "baseline area"). The approach set forth in this memo essentially mirrors the onshore AQCR's for purposes of establishing separate offshore baseline areas in order to implement the PSD increments on the OCS for the areas more than 25 miles from the State's seaward boundary.

Once the "baseline area" is determined according to the above approach, the "minor source baseline date" and the "baseline concentration" are determined in accordance with the rules at 40 CFR 52.21.

cc: Herman Wong, OEA
Pat Nair, OAWT,
Doug Hardesty, OAWT
Natasha Greaves, OAWT

Exhibit 8

AR-EPA-H-2

EPA Region 10, Environmental Justice Analysis for proposed Outer Continental Shelf Permit No. R10OCS030000, Kulluk Drilling Unit (July 19, 2011)

Environmental Justice Analysis

for proposed Outer Continental Shelf

Permit No. R10OCS030000

Kulluk Drilling Unit

This document contains the Environmental Protection Agency (EPA) Region 10's Environmental Justice Analysis for a Clean Air Act (CAA) permit authorizing exploratory drilling in the Outer Continental Shelf (OCS) in the Beaufort Sea. Pursuant to CAA section 328, 42 U.S.C. § 7627, Region 10 is reviewing an application for an OCS minor source permit and two OCS Title V[1] permits for Shell Offshore, Inc. (Shell) for operations of the Kulluk drill rig in the Beaufort Sea.

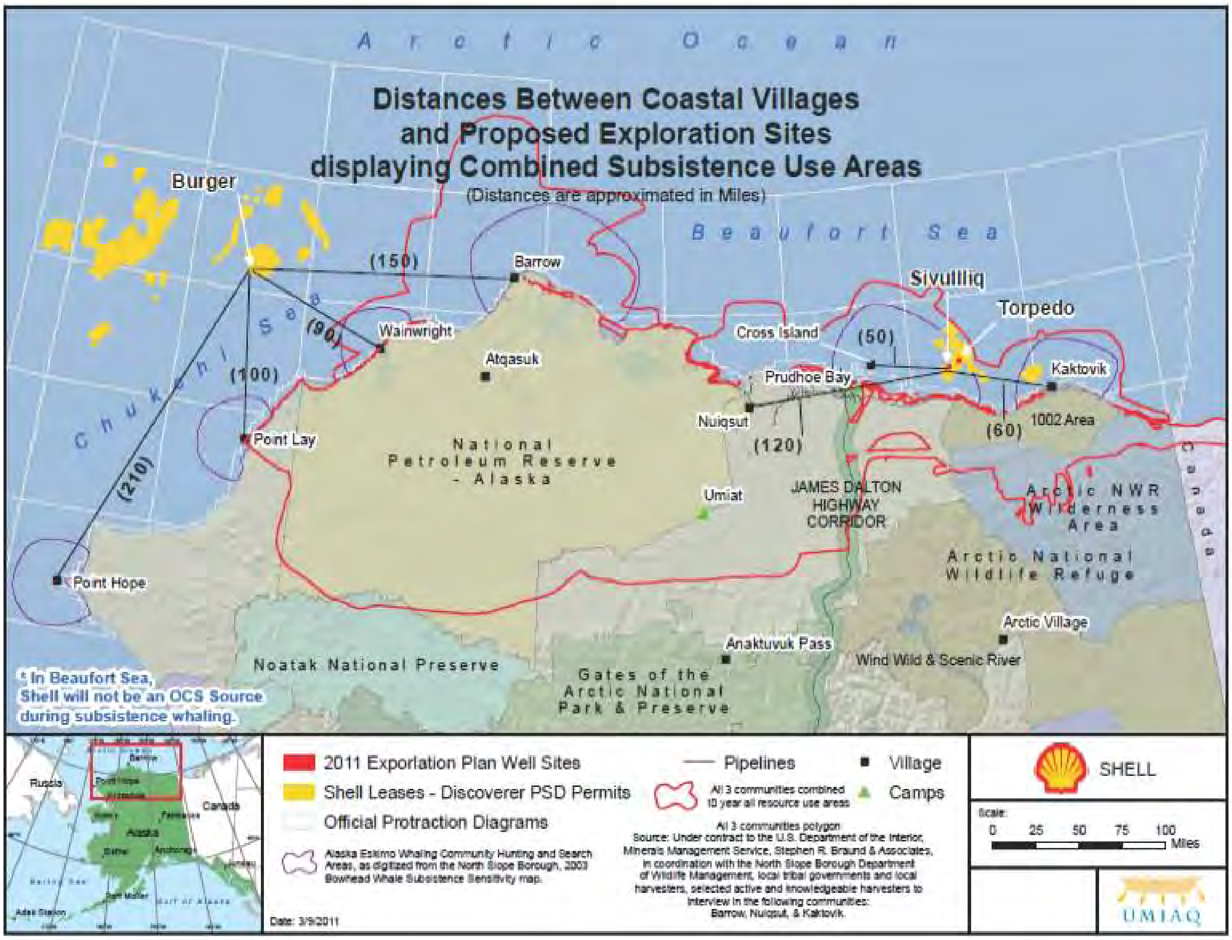
Shell's proposal is subject to the air quality permitting requirements under the OCS provisions of Title 40, Code of Federal Regulations (C.F.R.), Part 55 (Part 55). Under these regulations, the applicable requirements depend on the source's relative location to shore. OCS sources located within 25 miles of a State's seaward boundary are subject to the Federal, and to the State and local requirements of the Corresponding Onshore Area (COA), which have been incorporated into EPA's OCS regulations at Part 55. OCS sources located beyond 25 miles of a State's seaward boundary are subject to only Federal requirements – i.e., COA requirements do not apply. In Shell's case, the State of Alaska is the designated corresponding onshore area and the air quality permitting requirements of the Alaska Department of Environmental Conservation (ADEC), which have been incorporated into Part 55 apply. See 40 C.F.R. 55.15 Appendix A.

Shell requested that Region 10 impose emission limits for operation on lease blocks that are both within and beyond 25 miles of Alaska's seaward boundary. For operations within 25 miles of Alaska's seaward boundary, Shell submitted a minor permit application pursuant to the COA's minor permit program in Title 18 of the Alaska Administrative Code, Chapter 50 (18 AAC 50). For operations beyond 25 miles of Alaska's seaward boundary, Shell submitted a Title V operating permit application under 40 C.F.R. Part 71 (Part 71). Shell is also requesting that EPA issue a Title V operating permit under 40 C.F.R. Part 70 for continued operation within 25 miles of the seaward boundary. These permits will be collectively known as the "Title V Permit."

[1] Shell's project is permitted as "synthetic minor" source, with enforceable limits restricting potential to emit (PTE) to below major source thresholds. EPA's rules applying to sources of air pollution on the OCS (40 CFR Part 55) do not include provisions requiring construction permits for minor sources. Because of this, Shell has applied for the required Title V air quality operating permit in advance of construction.

dioxide (NO_x), carbon monoxide (CO), volatile organic compounds (VOC), and particulate matter (PM). In addition to these emission controls, the Kulluk drilling unit will use ultra low sulfur diesel fuel (ULSD) to reduce emissions of sulfur dioxide (SO_2 To further reduce impacts on the ambient air, the Associated Fleet will be fueled by ULSD and be subject to operational restrictions, and some units will be equipped with controls, including OxyCat and SRC. Emissions from the Associated Fleet when located within 25 miles of the Kulluk, together with emissions from the Kulluk, are considered in conducting an ambient air quality analysis to determine whether emissions from the project will cause or contribute to a violation of the NAAQS.

Figure 1 Subsistence Use Areas Mapped Over Exploration Sites



Northern Iñupiat Communities [2]

[2] The demographic and health factors have been chosen because EPA commonly associates them with vulnerability or susceptibility to adverse health effects from air pollution. In 40 CFR Parts 50 and 58 Primary National Ambient Air Quality Standards for Nitrogen Dioxide it states, “The term susceptibility generally encompasses innate (*e.g.*, genetic or developmental) and/or acquired (*e.g.*, age or disease) factors that make individuals more likely to

The North Slope is bordered by the Arctic Ocean to the north and the Brooks Mountain Range to the south. In all it encompasses approximately 89,000 square miles of northern Alaska. The incorporated villages of the North Slope Borough (NSB) include Point Hope, Point Lay, Wainwright, Atqasuk, Barrow, Nuiqsut, Kaktovik and Anaktuvuk Pass. These communities are situated completely above the Arctic Circle and are considered remote villages, with no roads between them. Most of the communities are coastal villages located near the Chukchi and Beaufort Seas.

The nearest towns or villages to Shell's exploratory operations in the Beaufort Sea are Kaktovik, Deadhorse, and Nuiqsut, which are located 14, 44, and 37 kilometers (8, 27, and 22 miles), respectively, from the closest lease block in the Beaufort Sea.

As discussed below, a review of demographic characteristics shows that these communities have a significantly high percentage of Alaska Natives, who are considered a minority under EO 12898, and a significant percentage of individuals who speak a language other than English at home.

Subsistence foods from traditional practices such as hunting (marine mammals, terrestrial and birds), fishing, and whaling are an important component of the Iñupiat diet.[3] In 2004, the Alaska Department of Fish and Game reported that over a 25 year period residents in the North Slope Borough harvested an average of 434 pounds of subsistence food per capita. [4]

Subsistence activities also play an important cultural role. In the words of the Environmental Director of the Iñupiat Community of the Arctic Slope (ICAS), speaking at the Environmental Justice Session held during the 2011 Alaska Forum on the Environment, "For thousands of years, our people have depended on a subsistence lifestyle for a large majority of our food, and also for our cultural and spiritual health. Through the subsistence hunt, we not only provide food for our families, but we also carry on the ancient traditions that have been passed down to us by our parents and grandparents. Our subsistence activities define who we are and bind us together as a community. We therefore depend on the land and sea for our survival and we hold the deepest and most profound respect for the natural resources that have sustained us for so many years.

experience effects with exposure to pollutants. The severity of health effects experienced by a susceptible subgroup may be much greater than that experienced by the population at large. Factors that may influence susceptibility to the effects of air pollution include age (*e.g.*, infants, children, elderly); gender; race/ethnicity; genetic factors; and preexisting disease/condition (*e.g.*, obesity, diabetes, respiratory disease, asthma, chronic obstructive pulmonary disease (COPD), cardiovascular disease, airway hyperresponsiveness, respiratory infection, adverse birth outcome) (ISA, sections 4.3.1, 4.3.5, and 5.3.2.8). Factors that may influence susceptibility and vulnerability to air pollution include socioeconomic status (SES), education level, air conditioning use, proximity to roadways, geographic location, level of physical activity, and work environment (*e.g.*, indoor versus outdoor) (ISA, section 4.3.5)" http://www.epa.gov/ttnnaaqs/standards/nox/fr/20100209.pdf

[3] Wernham, Inupiat Health and Proposed Alaskan Oil Development: Results of the First Intergrated Health Impact Assessment/Environmental Impact Statement for Proposed Oil Development on Alaska's Notrth Slope, 2007.

[4] Wolfe, R. J. 2004. Local traditions and subsistence: a synopsis of twenty-five years of research in Alaska. Technical Paper No. 284. Alaska Department of Fish and Game, Division of Subsistence, Juneau, Alaska.

Exhibit 9

AR-EPA-B-24

Order, *In the Matter of Pope and Talbot, Inc., Lumber Mill, Spearfish, South Dakota*, Petition No. VIII-2006-04
(Mar. 22, 2007)

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF	)	
Pope and Talbot, Inc., Lumber Mill	)	
Spearfish, South Dakota	)	
	)	ORDER RESPONDING TO
	)	PETITIONERS' REQUEST THAT
Permit Number: 28.4401-09	)	THE ADMINISTRATOR OBJECT
	)	TO ISSUANCE OF A
	)	STATE OPERATING PERMIT
Issued by the South Dakota Department of	)	
Environment & Natural Resource,	)	
Air Quality Program	)	
	)	Petition Number: VIII-2006-04
	)	
	)	

ORDER PARTIALLY GRANTING AND PARTIALLY DENYING PETITION FOR OBJECTION TO PERMIT

The United States Environmental Protection Agency ("EPA") received a petition on April 11, 2006, from Biodiversity Conservation Alliance, Rocky Mountain Clean Air Action, Defenders of the Black Hills, Native Ecosystems Council, Prairie Hills Audubon Society of Western South Dakota, Center for Native Ecosystems, Nancy Hilding, Brian Brademeyer, and Jeremy Nichols (hereafter "Petitioners"). Petitioners requested that EPA object, pursuant to section 505(b)(2) of the Clean Air Act ("CAA" or "the Act"), 42 U.S.C. § 7661d(b)(2), to the issuance of a state operating permit to Pope and Talbot, Inc., for operation of a lumber mill facility located at 1501 West Oliver Street, Spearfish, South Dakota. The permittee will be referred to as "Pope and Talbot" for purposes of this Order. Pope and Talbot is a wood products company that produces finished lumber and wood pellets from raw logs. The Pope and Talbot facility ("Facility") includes a wood waste boiler, a 1980 Lamb Debarker, a rotary drier, chip grinder, cooling tower and associated equipment. The various plant operations include: wood waste combustion, lumber drying in kilns, chip grinding, bark transfer and storage. The modified and renewed permit was issued by the South Dakota Department of Environment & Natural Resources ("DENR") Air Quality Program on February 15, 2006, pursuant to Title V of the Act, the federal implementing regulations at 40 C.F.R. Part 70, and chapter 34A-1-21 of the South Dakota Codified Laws and the Air Pollution Control Regulations of the State of South Dakota.

The petition alleges that the February 15, 2006 Pope and Talbot, Inc. renewed and modified Title V permit fails to: (1) ensure compliance with Carbon Monoxide (CO) emissions limits, (2) require sufficient periodic monitoring of CO emissions, (3) comply with Title V and South Dakota's State Implementation Plan (SIP) permit modification requirements, (4) require sufficient opacity monitoring, (5) require prompt reporting of deviations, (6) adequately support the determination that the Facility is not subject to Maximum Achievable Control Technology ("MACT") requirements for emissions of hazardous air pollutants, and (7) contains several problematic permit conditions that warrant objection. Petitioners have requested that EPA object to the issuance of the Pope and Talbot Title V permit for the foregoing reasons and pursuant to the requirements of section 505(b)(2) of the Act, 40 CFR § 70.8(d) and the applicable substantive federal and state regulations.

EPA has reviewed these allegations in accordance with the standard set forth by section 505(b)(2) of the Act, which places the burden on the Petitioners to "demonstrate to the EPA Administrator that the permit is not in compliance" with the applicable requirements of the Act or the requirements of 40 C.F.R. Part 70. *See also,* 40 C.F.R. § 70.8(c) (1); *New York Public Interest Research Group, Inc. v. Whitman*, 321 F.3d 316, 333 n.11 (2nd Cir. 2002).

In reviewing the merits of the various allegations made in the petition, EPA considered information in the permit record including: the petition; pertinent sections of the permit application; Mr. Nichols' November 11, 2005 comments to DENR in response to DENR's solicitation for public comment; DENR's December 22, 2005 response to Mr. Nichols comments (hereafter "Response to Comment"); final Operating Permit (Permit #28.4401-09) for Pope and Talbot, Inc. issued by DENR in February 15, 2006; Statement of Basis Document for Renewal with Modification of the Operating Permit issued by DENR in September 2005 (hereafter "Statement of Basis") and the Pope and Talbot Stack Test Report, February 2006. Based on the review of all the information before me, I grant in part and deny in part the Petitioners' request for an objection to the issuance of the renewed and modified Title V operating permit to Pope and Talbot, Inc. to operate a lumber mill in Spearfish, South Dakota for the reasons set forth in this Order.

STATUTORY AND REGULATORY FRAMEWORK

Section 502(d)(1) of the Act calls upon each State to develop and submit to EPA an operating permit program to meet the requirements of Title V. EPA granted final interim approval to the Title V operating permit program submitted by the State of South Dakota effective April 21, 1995. 60 Fed. Reg. 15066 (March 22, 1995). EPA also granted final full approval to South Dakota's Title V operating permit program effective February 28, 1996. 61 Fed. Reg. 2720 (January 29, 1996). *See also* 40 C.F.R. Part 70, Appendix A. Major stationary sources of air pollution and other sources covered by Title V are required to apply for an operating permit that includes emission limitations and such other conditions as are necessary to assure compliance with applicable requirements of the Act. *See* CAA §§ 502(a) and 504(a).

The Title V operating permit program does not generally impose new substantive air quality control requirements (which are referred to as "applicable requirements") but does require permits to contain monitoring, recordkeeping, reporting, and other conditions to assure compliance by sources with existing applicable emission control requirements. *See* 57 Fed. Reg. at 32250, 32251 (July 21, 1992). One purpose of the Title V program is to enable the source, EPA, States, and the public to better understand the applicable requirements to which the source is subject and to readily discern whether the source is meeting those requirements. Thus, the Title V operating permits program is a vehicle for ensuring that existing air quality control requirements are appropriately applied to a facility's emission units and that compliance with these requirements is assured.

Under section 505(a) of the Act and 40 C.F.R. § 70.8(a), States are required to submit all proposed Title V operating permits to EPA for review. Section 505(b)(1) of the Act authorizes EPA to object if a Title V permit contains provisions that are not in compliance with applicable requirements, including the requirements of the applicable SIP. *See also* 40 C.F.R. § 70.8(c)(1).

Section 505(b)(2) of the Act states that if the EPA does not object to a permit, any member of the public may petition the EPA to take such action, and the petition shall be based on issues that were raised with reasonable specificity during the public comment period, unless the petitioner demonstrates that it was impracticable to do so or unless the grounds for objection arose after the close of the comment period. *See also* 40 C.F.R. § 70.8(d). If EPA objects to a permit in response to a petition and the permit has been issued, EPA or the permitting authority will modify, terminate, or revoke and reissue such a permit consistent with the procedures in 40 C.F.R. §§ 70.7(g)(4) or (5)(i) and (ii) for reopening a permit for cause.

In a letter dated November 11, 2005, Petitioners submitted comments to the DENR during the public comment period, raising concerns with the draft Title V operating permit that provided a partial basis for this petition. DENR responded to the comments in a letter to the Petitioners dated December 22, 2005.

ISSUES RAISED BY PETITIONERS

I. <u>Carbon Monoxide (CO) Facility-wide Limit</u>

Petitioners raise several issues concerning the facility-wide CO limit contained in Pope and Talbot's permit. Petitioners claim that the permit fails to ensure compliance with the CO limit, because it does not contain conditions to ensure that the limit is not exceeded and does not require sufficient periodic monitoring of CO emissions. Petitioners assert further that because of these deficiencies with the CO limit, the Facility is not currently in compliance with Prevention of Significant Deterioration ("PSD") requirements at 40 CFR §52.21 et. seq. and a schedule of compliance may be needed.

Permit Condition 6.9 provides that Pope and Talbot shall not emit greater than or equal to 238 tons of CO per 12 months rolling period. DENR's Statement of Basis and Response to Comment states that DENR considers Pope and Talbot to be a major stationary source for PSD purposes based on CO emissions, but that a PSD permit review and permit were not required because Pope and Talbot was constructed before the 1974 promulgation of the PSD program. (Statement of Basis at 11). DENR also determined that the proposed addition of a grinder and cyclone (units #12 and #13) were not major modifications for PSD purposes. Id.

DENR's Response to Comment further states "Pope and Talbot proposed equipment is not subject to the PSD program.... There are no federal or state regulations that require Pope and Talbot to accept limitations to avoid the PSD program if they are not applicable to it." (Response to Comment at 4). DENR explains the origin of the CO emission limit (despite its determination that PSD requirements do not apply) as follows: Pope and Talbot does not believe that DENR's estimated carbon monoxide emissions from the boiler are accurate and does not believe it should be considered an existing major source under the PSD program. Pope and Talbot has agreed to accept a facility-wide carbon monoxide limit...until it can be demonstrated through a stack test that the carbon monoxide emissions are not above the major source threshold under the PSD program." Id at 2.

Based on DENR's Response to Comments and the discussion in the Statement of Basis, it appears that the limit established in Condition 6.9 is not required under the PSD program or required to avoid PSD requirements because the Pope and Talbot facility is considered a grandfathered source, and has not undergone a major modification for PSD purposes and thus is not subject to 40 C.F.R. § 52.21. However, there is also language in the permit suggesting that DENR established the condition based on a belief that it was required to avoid PSD applicability. Condition 9.1 of the permit provides that the Facility's exemption from PSD requirements is based on Condition 6.9.

EPA notes that DENR staff informed EPA staff in a recent (October 31, 2006) phone conversation that the source conducted a stack test and has demonstrated to the satisfaction of DENR that the CO emissions are below the PSD major source threshold. (February 2006 Stack Test Report, available from the South Dakota Department of Environment and Natural Resources (DENR), PMB 2020, Joe Foss Building, 523 East Capitol, Pierre, South Dakota 57501-3182)

I (A) Permit Fails to Ensure Compliance with CO Limits

Petitioners allege that the Title V permit fails to ensure compliance with the 238 tons per year (tpy) CO limit established in the permit to avoid PSD requirements. Petitioners argue that based on the operating rates allowed by the Title V permit, CO emissions can greatly exceed 238 tpy because the permit did not limit wood waste consumption, natural gas consumption and/or the hours of operation of the lumber mill. Petitioners allege that Condition 6.9 establishes the potential to emit ("PTE") emissions on the basis of an emission factor of 0.6 lb/MMBtu and that if the boiler were to operate 24 hours a day, seven days a week, CO emissions would amount to 267 tpy. Petitioners conclude that in order to ensure compliance with the permit limit of 238 tpy, there should be a limit on wood and natural gas consumption that correspond to such limit.

The Facility is required under Condition 6.9 together with Condition 5.8.4 of the Title V permit to monitor and record compliance with the plantwide CO synthetic minor source tpy limit (i.e., a limit established to keep the source's emissions below the major source threshold) established at the request of the Facility by the State under authority of the State operating permit requirements, ARSD 74:36:05:16.01(8). Condition 6.9 of the Title V permit establishes the plantwide CO emission limits at 238 tpy on a 12-month rolling average and specifies three equations prescribing exactly how the Facility must calculate total monthly CO emissions for the Boiler (unit #1) and the Dryer (unit #10). The permit requires the Facility to demonstrate that it is meeting limits on CO emissions by requiring monthly monitoring, recordkeeping and reporting of fuel usage (wood waste usage and natural gas fuel usage); recorded monthly fuels usage is multiplied by prescribed fuels emissions factors for CO, and this is summed with the previous months on a 12 month rolling basis to demonstrate continuous compliance with the annual 238 tpy CO limit. (See Permit Conditions 1.1, 5.1, 5.4, 5.8.4, and 6.9). Permit Standard Condition 1.1, Table 1, describes the emissions units, operations and processes at the Facility, including the 2 units with the potential to emit CO, the Dryer and the Boiler, their maximum operating emissions rate, and the associated controls.

In light of these Conditions, and in particular the 12-month rolling limit and terms of Condition 6.9, EPA does not agree that a specific limit on the amount of wood and natural gas consumed at the Facility is necessary to ensure compliance with Condition 6.9. Instead, the Facility has a 238 tpy annual limit on CO; compliance with this limit is assured by the monitoring requirements for CO emissions using the equations prescribed in Condition 6.9. Other conditions such as the annual compliance certification in Condition 5.6, recordkeeping and reporting requirements of Condition 5.1 , monitoring log requirement of 5.8.4 and annual records requirements of Condition 5.4 can serve to assure compliance with the emission limit. Therefore, I deny the petition on this issue.

I (B) <u>Permit Lacks Sufficient Periodic Monitoring of CO Emissions</u>

Petitioners allege that limits on CO emissions are unenforceable as a practical matter due to the lack of sufficient periodic monitoring of CO emissions. Petitioners cite Condition 6.9 as deficient because, they argue, it only requires monitoring of CO emissions once every five years in accordance with Condition 7.6 and that it is insufficient under 40 C.F.R. § 70.6(a)(3)(i)(B). They further argue that one-time performance testing fails to constitute sufficient periodic monitoring in accordance with 40 C.F.R. § 70.6(a) (3) (i) (B). Petitioners cite the *Appalachian Power Co. v. Environmental Protection Agency*, 208 F. 3d 1015 (D.C. Cir 200) case to support their claim that one time test does not constitute periodic monitoring.

Petitioner's allegations regarding Conditions 6.9 and 7.6 are incorrect. The permit as discussed above requires the Facility to demonstrate that it is meeting the 238 tpy limit on plantwide CO emissions every month based on required monthly monitoring and recordkeeping of fuel usage (wood waste usage and natural gas fuel usage). (See Permit Conditions 5.1, 5.4, 5.8.4, and 6.9). For the reasons discussed above, we find that Conditions 5.4, 5.8.4, 5.1 and 6.9 requiring monitoring and recordkeeping, and prompt deviation reporting meet the periodic monitoring requirement for demonstrating compliance with CO emissions. I, therefore, deny Petitioners' request on this issue.

I(C) <u>Schedule of Compliance May Need to be Included in the Title V Permit</u>

Petitioners allege that because the Title V permit fails to ensure that CO emissions are limited below the major source threshold under PSD, the permit is currently not in compliance with PSD requirements. Petitioners argue that because the Facility is in violation of an applicable requirement at the time of permit issuance, the permit must include a schedule containing a sequence of actions with milestones, leading to compliance with any applicable requirement in accordance with 42 U.S.C. § 7661b (b) (1) and 40 C.F.R. § 70.5(c) (8) (iii) (C).

I deny the petition on this claim because, for the reasons discussed above, the permit terms and conditions assure compliance with the 238 tpy CO limit; moreover, test results documented in the February 2006 stack test report prepared for the Facility seem to indicate the Facility plant-wide CO emissions are approximately 210 tpy; thus the emissions appear to be below the PSD major source level of 250 tpy. This suggests that, even in the absence of this 238 tpy limit, the Facility is not subject to PSD.

II. Permit Fails to Ensure Compliance with South Dakota SIP and Title V <u>Permit Modification Procedure</u>

Petitioners claim that the Condition 6.9 of the Title V permit allows CO emission factors for the boiler and the dryer to be changed through minor permit amendments, regardless of the significance of the changes in relation to CO emissions and regardless of the criteria set forth at Condition 3.4 in the Title V permit, which is also enumerated in the South Dakota SIP at ARSD 74:36:05:35[1]. Petitioners argue that the permit cannot automatically authorize a minor permit amendment as it does in Condition 6.9.

---

[1] **74:36:05:35. Requirements for minor permit amendments.** A minor permit amendment is an amendment to an existing permit and is issued by the secretary. A minor permit amendment may be issued by the secretary if the proposed revision meets the following requirements:

(1) It does not violate any applicable requirement;

(2) It does not involve significant changes to existing monitoring, reporting, or record keeping requirements in the permit;

(3) It does not require or change a case-by-case determination of an emission limit or other standard, a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis;

(4) It does not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement that the source has assumed to avoid an applicable requirement, a federally enforceable emissions cap assumed to avoid classification as a modification under any provision of Title I, and an alternative emissions limit approved pursuant to regulations promulgated under § 112(i)(5) of the Clean Air Act; and

Exhibit 10

AR-EPA-B-66

BPXA Prudhoe Bay Monitoring Map
(undated)

Exhibit B-66

B001904

Exhibit 11

AR-EPA-B-56

Beaufort Sea - Outer Continental Shelf Lease Ownership Map
(Aug. 30, 2011)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 SIXTH AVENUE
SEATTLE, WA 98101

TARGET SHEET

The following document was not printed.
This is due to the Original being:

X Data Files/Spreadsheet/Secured
____ PDF Exceeds 500 Pages

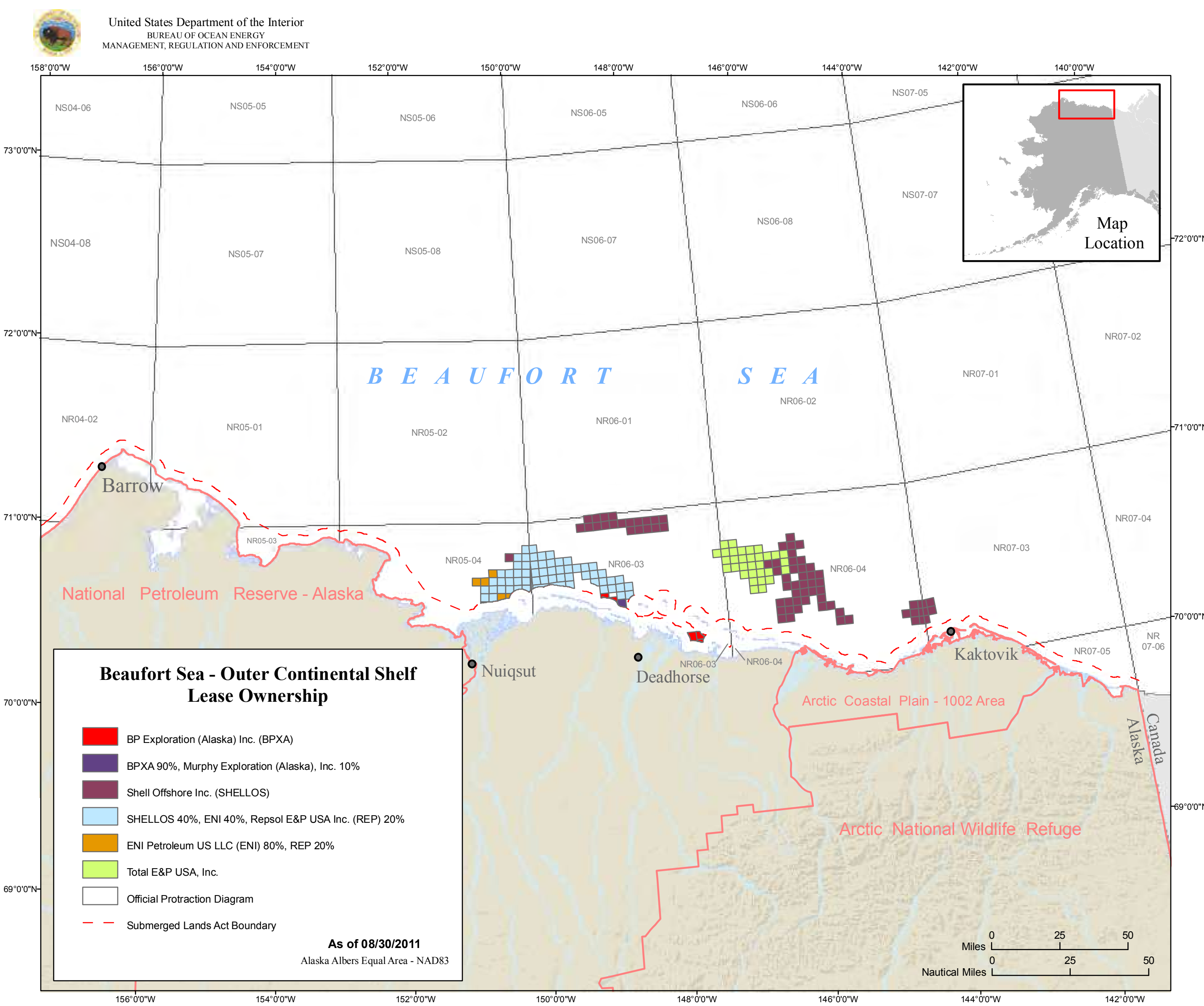
Document Information and Location

Exhibit No. :	B-56
Air Permit Name:	Shell Kulluk
File Category:	B - Guidance, Background Information, and Technical Analysis

2011-08-30 - Beaufort Sea - Outer Continental Shelf Lease Ownership Map

- 2011-08-30_Beaufort Sea OCS Lease Ownership Map

Original files can be found on the Shell Kulluk Administrative Record Compact Disc.


United States Department of the Interior
BUREAU OF OCEAN ENERGY
MANAGEMENT, REGULATION AND ENFORCEMENT
Beaufort Sea - Outer Continental Shelf
Lease Ownership
BP Exploration (Alaska) Inc. (BPXA)
BPXA 90%, Murphy Exploration (Alaska), Inc. 10%
Shell Offshore Inc. (SHELLOS)
SHELLOS 40%, ENI 40%, Repsol E&P USA Inc. (REP) 20%
ENI Petroleum US LLC (ENI) 80%, REP 20%
Total E&P USA, Inc.
Official Protraction Diagram
Submerged Lands Act Boundary
As of 08/30/2011
Alaska Albers Equal Area - NAD83
B E A U F O R T S E A
Barrow
Nuiqsut
Deadhorse
Kaktovik
National Petroleum Reserve - Alaska
Arctic Coastal Plain - 1002 Area
Arctic National Wildlife Refuge
Canada
Alaska
Map Location
Miles
Nautical Miles
0
25
50