Exhibit 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

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these older engines, Shell is prohibited from combusting any diesel fuel other than diesel fuel that meets the requirements of 40 CFR § 80.510(b) for nonroad diesel fuel. This requirement to combust a fuel satisfying ULSD specifications as it enters the engine applies only to the deck crane engines, and compliance is required beginning May 3, 2013. See Permit Condition G.3.5 for language assuring compliance with 40 CFR § 63.6604. Compliance with the 15 ppm fuel sulfur content limit is determined based upon information gathered in accordance with monitoring and recordkeeping requirements established in Permit Condition G.3.5. Prior to the drilling season, the sulfur content of diesel fuel in each storage tank serving the Kulluk deck crane engines is to be determined and recorded. For each fuel shipment received thereafter, Shell is to determine and record the sulfur content of the shipment as received.

H. CATEGORY – PERMITTING THE KULLUK AS A MINOR SOURCE

H.1 SUBCATEGORY – IN GENERAL

Comment H.1a: Several commenters contend that the project should be permitted as a major source rather than a minor source. Commenters question why the Draft Permit authorizes Shell to operate the Kulluk as a minor source when the Discoverer was permitted as a major source subject to the PSD program. The commenters describe the Draft Permit as establishing less stringent protections and setting a precedent that will impair the Arctic environment as oil and gas activity intensifies.

Response: In its permit application Shell requested that the permit contain federally enforceable restrictions to limit its potential to emit CO, SO_2, and NO_x to below PSD major source thresholds, and its potential to emit for GHGs to below the level at which GHGs become subject to regulation under the Tailoring Rule. See 75 Fed. Reg. 31,514 (June 3, 2010). A source that would otherwise exceed the applicable PSD major source threshold, and therefore be subject to PSD requirements may, as Shell has done here, seek to avoid PSD regulation as a major source by requesting that the permitting authority impose federally enforceable limits on the source's capacity to emit. *In re Shell Offshore, Inc. Kulluk Drilling Unit and Frontier Discoverer Drilling Unit*, 12 E.A.D. 357, 391-92 (EAB Sept. 14, 2007).

The Kulluk Permit includes enforceable limits that will restrict Shell's emissions to below PSD major source thresholds. If, as suggested by the commenters, Shell is permitted as a major source subject to PSD it would not be subject to enforceable limits to ensure minor source status and instead could be authorized to emit pollutants in excess of the PSD major source threshold. For this reason, Region 10 disagrees with the commenters' characterization of the Kulluk Permit as setting less stringent protections, and the assertion that it will set a bad precedent that impairs the environment. As a PSD synthetic minor source, Shell must comply with federally enforceable limits intended to limit its emissions to levels below applicable PSD major source thresholds, whereas sources permitted as major sources subject to PSD can, depending on the permit requirements, emit pollutants at levels that exceed applicable major source thresholds.

Comment H.1.b: Commenters contend that Shell's synthetic minor source status is based on arbitrary assumptions concerning Shell's operations. To support this contention, the commenters reference the NO_x emission limit of 240 tpy and state that this limit prevents Shell from operating its icebreakers for more than 38% of the operational period authorized under the Draft Permit, or roughly 46 days. The commenters note that unpredictable Arctic conditions may require more than 46 days of icebreaking during the operational period, and that it is unreasonable and arbitrary for Region 10 to expect that Shell can pack up and leave once emissions approach the permit limitations.

Response: As an initial matter, the 240 tpy NO_x limit referenced by the commenters does not limit the operation of the icebreakers to only 38% of the operational period. The NO_x limit is a source-wide limit that applies to all emission units in aggregate. Permit Condition D.4.1. Compliance with this limit will be determined through the monitoring, recordkeeping, and reporting requirements established in the permit.

As noted by the commenters, the frequency and intensity of ice conditions in the Arctic is difficult to predict. In its application, Shell relied on multi-year ice data from 2003-2005 to estimate that its icebreakers could be conducting ice management activities within 25 miles of the Kulluk for up to 38% of the time the Kulluk is an OCS Source. Permit Application Supplement at 37. Shell used this assumption along with many others (including the assumption that icebreakers would be operating at maximum load at all times while managing ice within 25 miles of the Kulluk) to estimate the maximum expected emissions for the purpose of assessing its ability to conduct exploratory operations while at the same time limiting emissions to less than PSD major source thresholds. OCS Permit Applications, Conical Drilling Unit Kulluk, Beaufort Sea – Application Forms (Permit Application), Appendix G. Shell estimates that icebreaking activity will account for 92 of the 229 tons of allowable NO_X emissions. For additional discussion of ice management see response to comments in Category FF.

The commenters concern appears to be that the assumption Shell relied on for ice management may not reflect actual ice conditions during operations. This may be the case. However, in requesting synthetic minor limits and relying on this assumption Shell has accepted the risk that, if ice conditions are greater than assumed, Shell may be required to reduce emissions from other units or curtail its drilling season to comply with the NO_x limit. See Response to comment FF.3. Furthermore, the ice management assumption relied upon by Shell does not necessarily mean that Shell would be effectively limited to 46 days (38% of 120 days) of ice management activities. In conjunction with the 38% ice management assumption, Shell assumed the icebreakers would be operating at maximum capacity when actual operations will likely be conducted at less than maximum capacity, and actual emissions would therefore be less than assumed. In addition, Shell's Camden Bay Exploration Plan includes an Ice Management Plan that describes how it will forecast and track ice and weather conditions, and describes procedures for operational curtailment. Therefore, the Region does not think it is arbitrary or unreasonable to expect that Shell will be able to forecast ice management needs and curtail or cease operations if necessary to comply with the NO_x limit.

Comment H.1.c: Commenters express concern that restrictions on the source's PTE are not consistent with Shell's representations to other agencies. The commenters refer to EPA guidance concerning a permittee's request for limits to avoid new source review when in reality the requested limits are not how the permittee intends to conduct operations. The commenters request that Region 10 ensure Shell will abide by the restrictions in the Draft Permit and cite to representations made by Shell to BOEMRE and in its Incidental Harassment Authorization that differ from representations made in its application to Region 10. Commenters further state that, based on information submitted in the Camden Bay Exploration Plan and its air permit application, Shell could only drill one well in Camden Bay this year and ask that Region 10 either confirm Shell will drill only one well or issue a major source PSD permit to Shell.

Response: The fact that Shell's Camden Bay Exploration Plan or some other authorization might authorize operation in a different manner or for a longer period of time than authorized under the Kulluk Permit does not relieve Shell of its obligation to comply fully with the Kulluk Permit. As an initial matter, the operational restrictions on drilling in the permit are not established by days but by hours of operation. See Permit Conditions D.3.3 and D.3.4. In its permit application, Shell assumes that it is engaged in the identified drilling activity for 24 hours a day for the specified number of days. The Environmental Impact Assessment cited by the commenters already includes the five additional days to construct the MLC in the estimate of 44 drilling days for the Torpedo prospect drill site and 34 drilling days for the Sivulliq prospect site. In addition, Shell's permit application describes scenarios in which it would not drill a well to depth but might only establish the MLC or any other portion of a well. Permit Application Supplement at 25. These factors make it possible that Shell could construct wells, or portions of wells, at both the Torpedo and Sivulliq prospects in a single season. Shell acknowledged in its permit application that it could only drill as many wells, or portions of wells, as ice conditions or the requested limits in the permit allow. Id. For these reasons, Region 10 does not agree with the commenters that it is necessary to confirm that Shell will only drill one well, or issue a major source PSD permit in the absence of this confirmation.

The discussion in the guidance cited by the commenters is a discussion of "sham operational limits" whereby a source applies for a permit as a minor source so as to be able to begin construction without obtaining a major source permit (such as a PSD permit) and then subsequently increases its emissions once it has received a major source permit. Limiting Potential to Emit in New Source Permitting, dated June 13, 1989, at 10-11 (1989 PTE Guidance). Although Shell has requested synthetic minor source limits, there is no indication in the permit record that Shell intends to later apply to Region 10 to remove these synthetic limits. Moreover, Shell must comply with all requirements of the Kulluk Permit and failure to do so is a violation of the CAA. See Permit Condition A.3. As explained in the 1989 PTE Guidance, "attempts to expedite construction by securing minor source status through the receipt of operational restrictions from which the source intends to free itself shortly after operation are to be treated as circumvention of the preconstruction review requirements." Whether an original request for a synthetic minor permit is a “sham” may be evaluated when a request to remove such limits is received by the permitting authority. If Shell submits an application for a major source permit after it commences operations, Region 10 will evaluate the application consistent with the 1989 PTE Guidance, as well as other authorities.

Comment H.1.d: Commenters state that the permit must include a requirement that if the synthetic minor limits are relaxed the source will be subject to the requirements of 40 CFR § 52.21(r)(4), and that if the permit limits are exceeded the source will trigger PSD requirements and should be required to obtain a PSD permit.

Response: It is not necessary to include 40 CFR § 52.21(r)(4) as a condition in the Kulluk Permit. This regulatory provision requires that if a source becomes a major source solely by virtue of a relaxation of any enforceable limitation on its capacity to emit a pollutant, the source will be subject to the PSD requirements at 40 CFR §§ 52.21(j) to (s) as though the source had not commenced construction. Region 10 has no information that Shell intends to request that any enforceable limitation be relaxed during the term of the Kulluk Permit. Shell is required to comply fully with the Kulluk Permit. If Shell requests a permit change or modification that relaxes an enforceable limit such that it becomes a PSD major source it will be subject to 40 CFR § 52.21(r)(4). In addition, Region 10 will evaluate any operation in excess of PSD-avoidance limits consistent with the 1989 PTE Guidance and the Memorandum from Eric V. Schaeffer, EPA, re: Guidance on the Appropriate Injunctive Relief for Violations of Major New Source Review Requirements, dated November 18, 1999.

Comment H.1.e: A commenter at the Barrow public hearing stated that all Region 10 permits for operations in the Arctic should require BACT.

Response: OCS sources are required to comply with the provisions of PSD program at 40 CFR § 52.21. 40 CFR § 55.13. The PSD program requires, among other things, that new or modified major stationary sources apply BACT. Shell will be a PSD minor source, not a PSD major source, and therefore is not required to apply BACT.

Comment H.1.f: Commenters at the Anchorage and Barrow public hearings stated that as a minor source Shell is not required to undergo a BACT analysis. One commenter noted that as a PSD minor source the Kulluk will have lower emissions than if it were permitted as a PSD major source, and that Shell has installed emission controls that are extensive. One commenter noted that Shell is currently replacing the main engines and other sources on the Kulluk with newer, more efficient and cleaner systems. The commenter contends that the intent of BACT is to ensure best currently available technology and that Shell has done this with the updates to the Kulluk emission units.

Response: Region 10 agrees with the commenters that as a minor source Shell is not required to conduct a BACT analysis or be subject to BACT, and may have lower emissions than if it were permitted as a PSD major source. As a BACT analysis for the Kulluk has not been conducted, the Region disagrees with the commenter’s implication that the updated emission units constitute BACT.

H.2 SUBCATEGORY – PSD APPLICABILITY THRESHOLD FOR GREENHOUSE GASES

Comment H.2.a: Commenters contend that Region 10 applied the wrong major source threshold for CO_2e in the Draft Permit. The commenters note that the Tailoring Rule provides that if a source is not major for any other pollutant the major source threshold is 100,000 tpy, but if the source is major for another pollutant the threshold is 75,000 tpy. The commenters reason that because Shell's pre-permitted PTE for NO_x, CO, and SO_2 would make it a major source for these pollutants, the applicable major source threshold for CO_2e is 75,000 tpy.

Response: The Tailoring Rule referenced by the commenters establishes applicability criteria that determine when GHGs emitted from stationary sources and modification projects become subject to regulation under the PSD and Title V programs. 75 Fed. Reg. 31,514 (June 3, 2010). The rule provides that GHGs emitted from a stationary source will be subject to regulation if the source is a new major source for a regulated NSR pollutant that is not GHG, and emits or has the potential to emit 75,000 tpy CO_2e or more, or if the new source would otherwise emit or have the potential to emit 100,000 tpy CO_2e or more. See 40 CFR § 52.21(b)(49)(iv); 75 Fed. Reg. at 31,523-24. The Tailoring Rule also explained that in order for a source's GHG emissions to trigger PSD or Title V requirements, the GHG emissions "must equal or exceed both the applicability thresholds established in this rulemaking on a CO2e basis and the statutory thresholds of 100 or 250 tpy on a mass basis." 75 Fed. Reg. at 31,518.

Under the PSD program, as applied to Shell's stationary source, a "major stationary source" is any source which emits or has the potential to emit any pollutant subject to regulation under the CAA in amounts equal to or greater than 250 tpy. 40 CFR § 52.21(b)(1). The PSD regulations define potential to emit as the maximum capacity of a source to emit under its physical and operational design, including any physical or operational limitation on the capacity of the source to emit if the limitation is federally enforceable. 40 CFR § 52.21(b)(4).

As noted by the commenter, Shell's pre-permitted PTE exceeds the 250 tpy threshold for non-GHG for three pollutants. However, Shell requested, and Region 10 has included, federally enforceable limitations in the Kulluk Permit that reduce the source's potential to emit to below 250 tpy for all non-GHG pollutants subject to regulation for purposes of NSR. Accordingly, Shell is not a new major source for a non-GHG regulated NSR pollutant and thus is not subject to the 75,000 tpy CO_2e applicability threshold for such sources. Instead, Shell would be considered a major source for PSD permitting purposes if it emits or has the PTE 100,000 tpy CO_2e and 250 tpy GHG on a mass basis. Its requested limits for CO_2e keep it below the applicable threshold, therefore the source's GHG emissions are not "subject to regulation" for PSD permitting purposes and PSD requirements do not apply.

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.

Moreover, the Kulluk Permit differs from the permit at issue in the Region 9 letter because it establishes a NO_x limit of 240 tpy, which provides a greater cushion and more confidence with respect to the PSD major source threshold than the 249 tpy limit at issue in the Region 9 letter. In addition, the permit includes requirements to ensure that emissions do not exceed this threshold, including but not limited to source testing of engines that are anticipated to generate approximately 91 percent of emissions, calculating emissions from these engines based upon worst-case emission factors (lb/gal) and continuously measuring and recording hourly the flow of diesel fuel to these engines (gal/hr). For those engines employing SCR to reduce emissions, the permit requires that a CMS measure and record operating parameters associated with the control device. On those occasions when the CMS detects operation of the control device in a manner different from that observed during stack testing, the permit requires that an uncontrolled emission factor be employed to calculate NO_X emissions. The application of a CMS and the use of uncontrolled emission factors increase confidence that the source's actual emissions will not be greater than reported.

Furthermore, the Kulluk Permit contains adequate and enforceable monitoring, recordkeeping, and reporting requirements to ensure that Shell complies with the NO_x and other emission limits. As noted in the Region 9 letter, if a major source threshold is exceeded a facility may trigger PSD requirements and may be treated as a source that should have obtained a PSD permit. Memorandum from Eric V. Schaeffer, EPA, re: Guidance on the Appropriate Injunctive Relief for Violations of Major New Source Review Requirements, dated November 18, 1999, at 5-6. For these reasons, Region 10 disagrees with the commenters that a buffer calculated as a percentage of the major source threshold is necessary in this case.

I.3 SUBCATEGORY – DETERMINING COMPLIANCE WITH PTE LIMITS

Comment I.3.a: Commenters state that limits on emissions of criteria pollutants are not practically enforceable because adequate monitoring is not in place to assure compliance. As an example, the commenters cite to the Statement of Basis (p. 38) which states: "[c]ompliance with the CO and NO_X emission limits is determined by multiplying measured fuel by periodically confirmed emissions factors." The commenters contend that the Draft Permit authorizes the use of default emission factors until unit-specific emission factors are determined through testing, and for some emission units there is no requirement to test for unit-specific factors. The commenters state that because the permittee has failed to identify the emission units it will use, this approach creates inherent uncertainty that necessitates thorough source testing. This inherent uncertainty remains unresolved, the commenters continue, because some emission units will not be tested. The commenters contend that because there will be no way to determine whether the default emission factors are wrong, the emission limits for CO and NO_X will be unenforceable as a practical matter. The commenters further state that the failure to obtain unit-specific data for all units is particularly problematic because the AP-42 emission factors that Region 10 relies on are notoriously inaccurate. The commenters cite to AP 42, Volume I, Fifth Edition for support that EPA does not recommend the use of AP-42 factors as source-specific permit limits and/or as emission regulation compliance determinations.

Response I.3.a: The permit requires the use of emission factors to determine compliance with both NAAQS- and PTE-based NO_X and CO emission limits and requires source-specific verification of emission factors through source testing for the emission units that make up most of the allowed NO_X and CO emissions. Some smaller or infrequently used emission units, representing a small portion of the total NO_X and CO emissions, are not required to be tested. For those units that are not required to be tested, the NO_X and CO emission factors are based on either AP-42 emission factors or, when available, source test data from Shell's Discoverer drillship and Associated Fleet.

In consideration of the comments received, and to be sure there is a reasonable margin of safety that assures compliance, Region 10 is adding a requirement to test NO_X and CO emissions from each incinerator. Permit Condition E.3.2. Given the unique applications of the incinerators on these vessels, Region 10 believes this additional emission factor verification is appropriate and reasonable. After adding this additional incinerator testing, the permit will require emission testing of emission units that constitute 91% of the total NO_X emissions and 97% of the total CO emissions.

For emission units for which the permit does not require testing (emergency generators, seldom-used sources and OSRV work boats) and that rely on NO_X emission factors based on Discoverer test data, in response to comments received, Region 10 is adjusting the emission factors to reflect very conservative 90th percentile (or higher) values from the test data. See response to comment M.2.c. The only units that rely on AP-42 for NO_X emission factors are the heaters and boilers, which constitute only one percent of total NO_X emissions. Region 10 expects AP-42 emissions factors for heaters and boilers to be a conservative representation of actual emissions. EPA expects AP-42 emissions factors for heaters and boilers to be a conservative representation of actual emissions. While AP-42 predicts an emission factor of 0.02 lb/gal for heaters and boilers, Shell testing of its boilers residing on the Discoverer shows a range of values between 0.011 lb/gal and 0.015 lb/gal.[6]

The emission units that will not be tested to verify CO emissions factors (heaters and boilers, emergency generators, seldom-used sources and OSRV work boats) rely on AP-42 emission factors. While AP-42 emission factors are considered average values for the size-specific categories of emission units the emission factors represent, Region 10 believes that the emission factors are reasonable for use in this permit given that AP-42 emission factors will represent only 3% of the total CO emissions. Actual emissions from some emission units may be higher and some lower than the AP-42 emission factors predict.

[6] 0.11 lb/gal = (8.33 x10^{-2} lb/MMBtu) x (MMBtu/1x10^6 Btu) x (131180 Btu/gal)
0.15 lb/gal = (1.18 x10^{-1} lb/MMBtu) x (MMBtu/1x10^6 Btu) x (131180 Btu/gal) See June 16, 2011 email from Rodger Steen to Dan Meyer.

Emission testing conducted by Shell on two Discoverer boilers showed CO emissions very near what AP-42 predicts. The tests conducted by Shell resulted in CO emission factors of 0.004 and 0.007 lb/gal, while AP-42 predicts an emission factor of 0.005 lb/gal.[7] In response to the comments received, EPA has decided to use the higher of the two test values (0.007 lb/gal) in place of the AP-42 emission factor.

According to Shell, OSRV work boats will be deployed 5 days a week for 6 hours a day to conduct exercises. See "Anticipated Kulluk Operating Maximum" in Permit Application Supplement at 326. Emissions data supplied by Shell for one of the potential work boats to be deployed suggests the actual emission factor for the propulsion engines is one-tenth the value AP-42 predicts. The engine manufacturer's data provided by Shell suggests an emission factor of 0.006 lb/gal, while AP-42 suggests an emission factor of 0.112 or 0.125 lb/gal, depending on the engine rating.[8] Shell intends to install a brand new emergency generator on the Kulluk; it is predicted operations will be two hours each month to exercise the generator. Seldom-used sources consist of equipment such as life boats and are, as the name suggests, expected to operate infrequently. Region 10 believes the permit strikes an appropriate balance between the need for accurate emission factors to reliably calculate emissions for comparison to permit limits and the complexity of testing numerous emission units in a short period of time.

Comment I.3.b: Commenters assert that the CO_2e emission limit of 80,000 tpy is not practically enforceable because Region 10 neglected to require monitoring or controls for emissions of methane. Commenters contend that methane is a powerful greenhouse gas with a warming potential 21 times greater than CO_2, and methane emission must be included in calculating whether a source is subject to the Clean Air Act's greenhouse gas controls. When a rig drills into porous, the commenters state, hydrocarbon bearing rock, methane mixes into the drilling muds and is brought to the surface. The commenters state that some of this methane will be emitted through a vent, and therefore must be counted toward Shell's potential to emit CO_2e. The commenters state that Region 10 assumes that the drilling mud system will vent no more than 399 pounds of methane per month (4 tons per month of CO_2e), and makes this assumption on assurances from Shell based on its past drilling experience. The commenters state that ConocoPhillips estimated methane emissions at 183 tons per month, which the commenters calculate as 46 times Shell's estimate. The commenters take issue with Region 10's determination not to require Shell to control, monitor, or report methane emissions, and assert that the lack of monitoring or reporting makes the owner-requested limit for CO_2e unenforceable as a practical matter.

Response: EPA has recognized that there are sources for which inherent physical limitations for the operation restrict the potential emissions of individual emission units.

[7] 0.004 lb/gal = (0.0311 lb/MMBtu) x (MMBtu/1x10^6 Btu) x (131,180 Btu/gal)
0.007 lb/gal = (0.05 lb/MMBtu) x (MMBtu/1x10^6 Btu) x (131,180 Btu/gal) See June 16, 2011 email from Rodger Steen to Dan Meyer.

[8] Support Vessel Parameters, Permit Application Supplement at 154. 0.006 lb/gal = (0.155 g/hp-hr) x (hp/7000 Btu) x (lb/453.592 g) x (131,180 Btu/gal)

Where these inherent physical limitations can be documented by the source and confirmed by the permit issuer, the permit issuer has the authority to make such judgments and factor them into estimates of stationary source potential emissions. See Memorandum from John S. Seitz, EPA, re: Options for Limiting the Potential to Emit (PTE) of a Stationary Source Under Section 112 and Title V of the Clean Air Act (CAA), dated January 25, 1995 (Options for Limiting PTE) at 8.

Methane emissions from the drilling mud system are subject to operational restrictions that limit operations to 120 days between July and November, and limit drilling activity to 1,632 hours. These operational limits are accompanied by monitoring in the form of recordkeeping. See Permit Condition D.3.6. In this case, Shell calculated the potential methane emissions from the drilling mud system based upon the maximum expected capacity over the five-month period of operation taking into consideration inherent physical limitations and actual well data. See Permit Application, Appendix E. EPA has acknowledged that where inherent physical limitations exist, it may be appropriate to rely on a reasonable and realistic "upper-limit" projection in identifying the "maximum capacity" of a source for the purpose of estimating their PTE. See e.g., Memorandum from John Seitz, EPA, re: Calculating Potential to Emit (PTE) and Other Guidance for Grain Handling Terminals, dated November 14, 1995, at 4-5; Options for Limiting PTE at 8.

To add a measure of safety in issuing the Draft Permit, Region 10 assumed all of the emissions from the drilling mud system (which includes the cuttings/mud disposal barge) will be point source emissions whereas, in actuality, a significant amount of the emissions from the drilling mud system and all of the emissions from the cuttings/mud disposal barge meet the definition of fugitive emissions and do not have to be counted for this source category in determining a source’s potential to emit under the PSD program. See 40 CFR § 52.21(b)(1)(iii).

In response to these comments, Region 10 contacted Shell on September 8, 2011, to discuss the methane estimation and request additional well information previously-claimed by Shell as confidential to confirm that the estimate of methane potential to emit it previously provided to Region 10 is a reasonable upper-bound estimation. Shell provided the additional documentation of actual well data. See email from Susan Childs, Shell, to Doug Hardesty, Region 10, re: Shell Mud and Cuttings Degassing Emissions, dated September 16, 2011. The information provided shows that Shell relied on actual well pressure, temperature, porosity, and depth of the hydrocarbon bearing zone from past Arctic exploration projects in its estimation.

In reviewing Shell’s new information, Region 10 identified an error in the methane emission factor in the draft Kulluk permit. As in the Shell Discoverer permits, Region 10 conservatively assumed that Shell’s estimation represented only one well and adjusted the monthly emission factor by a factor of four to represent four wells (a reasonable upper-bound estimate of the number of wells that could be drilled in a single season). The emission factor is the draft Kulluk permit was missing this adjustment. The final Kulluk permit will include the adjusted methane mission factor (1,596 pounds CH4 per month) to be consistent with the Discoverer permits. Region 10 has also amended the synthetic minor12-month rolling diesel fuel combustion limitation (Condition D.4.6) to account for the revised estimate of CO_2e potential emissions attributed to mud degassing. Because mud degassing GHG emissions are relatively insignificant compared to fuel combustion GHG emissions, the 12-month rolling diesel fuel usage limit has only decreased 0.1% from 7,011,323 gallons to 7,004,428 gallons.[9]

As in the case of the reasonable, upper-bound projections that EPA believes are appropriate for determining the PTE of grain terminals, Region 10 believes that the emission estimate for methane emissions from Shell's mud drilling system (17 tons per month of CO_2e) assumed in the emission limit on total GHGs is a reasonable upper-bound projection for Shell's operations and is not expected to be exceeded under any reasonably anticipated operating scenario. This is especially true given the other conservative assumptions that Region 10 is applying to Shell's estimate to provide a wide margin of safety (considering both point source and fugitive emissions in the estimate and assuming the yearly estimate is emitted in each of the five months).[10]

For comparison purposes, EPA recommends grain terminals apply a safety factor of 1.2 to the highest of the previous five years of throughput to constitute a realistic upper-bound potential to emit. See Memorandum from John Seitz, EPA, re: Calculating Potential to Emit (PTE) and Other Guidance for Grain Handling Terminals, dated November 14, 1995, at 5. It is important to emphasize that, even with these conservative assumptions, the GHG emissions (85 tons per year CO_2e) from the drilling mud system represent only 0.11% of the total GHG emissions (80,000 tons per year CO_2e) allowed under the permit.

Region 10 believes that assuming such a conservatively high estimate of the methane emissions that would be emitted from the drilling mud system operating at its maximum design operation rate, coupled with the operational limit on the duration of the operations and other permit restrictions, are collectively sufficient to ensure methane emissions from the drilling mud system do not exceed 17 tons per month of CO_2e, and that overall CO_2e emissions do not exceed 80,000 tpy on a 12-month rolling basis. Because of the inherent limitations that exist, and considering the small contribution from the mud drilling system to overall GHG emissions from the Kulluk and Associated Fleet as a whole, Region 10 does not believe it is necessary or appropriate to monitor emissions from, or operations of the drilling mud system, aside from the monitoring already required in the permit

[9] 79,080 ton CO_2e = 80,000 ton CO_2e (ORL) – 835 ton CO_2e (waste incineration) – 85 ton CO_2e (mud degassing)
7,004,428 gallons = (79,080 tons CO_2e) x (2000 lb CO_2e/ton CO_2e) x (gal diesel/22.58 lb CO_2e)

[10] Region 10 is aware that ConocoPhillips provided an estimate of emissions from its mud drilling system that is much higher than that provided by Shell to support this permit. Region 10 has closely examined the estimates provided by both companies along with a comparison of the methodologies offered by Shell in its September 20, 2011 comments to EPA regarding the permitting of ConocoPhillips jackup drill rig. Shell's estimate is based on well information from past arctic exploration projects. The fact that one company has chosen to rely on even more conservative assumptions in estimating its potential to emit from similar operations does not undermine the validity of another company using less conservative, but still reasonably conservative assumptions in estimating its emissions where it has a reasonable basis to do so.

including monitoring the duration of operations. Moreover, Region 10 believes that the monitoring, recordkeeping, and reporting included in the permit for the limits on emissions, fuel, waste, and operations that collectively limit emissions to below the Tailoring Rule "subject to regulation" threshold for GHGs together constitute a "verifiable method to attain and maintain each limit" within the meaning of 18 AAC 50.225 of the COA regulations.

J. CATEGORY – LIMITS TO PROTECT THE NAAQS

J.1 SUBCATEGORY – ENFORCEABILITY OF EMISSION LIMITS

Comment J.1.a: Commenters state that EPA guidance provides that emission limits are "sufficient to limit potential to emit" when they include "requirements to install, maintain, and operate a continuous emission monitoring (CEM) system and to retain CEM data, and specifies that CEM data may be used to determine compliance with the emission limit." The commenters contend that the present circumstances warrant CEM to ensure permit conditions are enforceable, and are concerned that the Region has not required CEM where permit provisions are based on a new model and new algorithms that have not been tested for the Arctic. The commenters believe that only monitoring the combustion of fuel or waste is not sufficient to protect air quality given the modeling uncertainties underlying the permit provisions.

Response: The commenters have provided no support for the assertion that fuel and waste combustion monitoring is not sufficient to protect air quality. In fact, the waste monitoring required in the permit is needed to confirm NSPS applicability rather than for monitoring compliance because waste combustion rates are conservatively assumed to be at the maximum any time an incinerator operates. For a discussion on why Region 10 believes the requirements established in the permit are both legally enforceable and enforceable as a practical matter and sufficient to limit potential to emit see responses to comments in Subcategory I.1. With respect to the concern that fuel and waste combustion monitoring is not sufficient to protect air quality, the commenters have provided no support for this assertion. Although there is some uncertainty inherent in all modeling analyses (because it is by nature predictive), Region 10 believes the modeling underlying the NAAQS requirements and the compliance assurance provisions in the permit are sufficient to ensure the NAAQS will be protected.

Continuous Emission Monitoring System (CEMS) are a means of ensuring compliance with emission limits and may be an appropriate alternative if setting enforceable operational parameters for control equipment is infeasible. See 1989 PTE Guidance at 7-8. CEMS may also be appropriate where sources are experiencing regular compliance problems. CEMS are not the only means, however, of assuring compliance with limits on potential to emit and NAAQS-based emission limits. Shell's proposed exploratory operations are unusual as compared to other sources because the emission units consist of numerous engines and generators with numerous release points (stacks) on the Kulluk and a fleet of many support vessels. SCR and OxyCat controls are required on multiple engines on three different vessels. CEMS are expensive to purchase, maintain, and operate, but more importantly, there are practical considerations that Region 10 had to consider in this case, including the fact that emission units, control equipment, and monitoring equipment will be operating in a remote, harsh, Arctic environment, and deck space on board the vessels is limited. Furthermore, potential to emit is determined on a source-wide basis making it less critical to be precise on an individual emission unit basis. Similarly, NAAQS compliance is in jeopardy when the total emissions impacting a receptor point are higher than allowed. Higher than expected emissions at one stack, are offset by other stacks emitting less than expected. Region 10 believes that the permit assures compliance with the PTE and NAAQS limits through an appropriate level of monitoring that reflects the unique attributes of this source.

The permit requires a regimen of stack testing and emission calculations, in conjunction with a continuous monitoring system for parametric monitoring of control equipment to ensure compliance with emission limits. This is in addition to other operational restrictions that will have the effect of restricting the source's emissions and help ensure compliance with the NAAQS-based limits. Region 10 believes that the control equipment parametric monitoring required by the permit – temperature, urea feed, catalyst activity for SCR (Permit Condition F.3) and temperature and catalyst activity for the oxidation catalyst device (Permit Condition F.4) – are effective means for ensuring that the controls are working properly and achieving the projected emission reductions. For uncontrolled emission units, the permit requires monitoring and reporting operational rates including fuel and hours of operation. The commenters have provided no information to indicate that the required monitoring of fuel, hours of operation, and control equipment will not be accurate. Multiplying the tracked fuel rates by source-specific emission factors determined by source testing for most of the emission units will provide a reasonable assurance of compliance with emission limits in the permits. The commenters have provided no information to the contrary, nor have the commenters identified any specific requirement to use CEMS in this circumstance. Contrary to the commenters' assertion, monitoring emissions using CEMS has no bearing on the accuracy of the new algorithms used by Shell for modeling. Region 10 continues to believe that CEMS are not necessary to provide a reasonable assurance of compliance with the emission limits in this permit. See also response to comment M.3.c.

Comment J.1.b: Commenters assert that limits established to ensure compliance with the NAAQS are not enforceable. The commenters take issue with the establishment of limits on pounds per hour or day, and state that it is inappropriate to assess NAAQS compliance with pound per hour calculations without any underlying, enforceable measure (e.g., operational or production limits) to assure that those emissions limits are met.

Response: The commenters have not specified why they believe it is necessary to create operational and production limits in addition to mass emission limits for NAAQS compliance, and cite no legal authority requiring such limits. The permit contains enforceable conditions to address NAAQS compliance.

The NAAQS-based emission limits are based on predicted emission rates used in modeling to demonstrate compliance with NAAQS. Compliance with the emission rates is determined by multiplying the measured operational rates (fuel or waste feed rates) by emission factors that are specified and developed through testing under the permit. Because the emission limits are specified in the permit and the emission factors are set through procedures in the permit, the maximum amount of operation (fuel or waste feed) is effectively restricted as well.

For instance, Permit Condition 6.1.1.1 limits NO_x during drilling from emission units K-1A through K-1D to 19.0 pounds per hour. The emission factor for NO_x emissions from these same emission units, found in Table D.2.1 of the permit, is 0.049 pounds per gallon of fuel combusted. If Shell operates these units such that they combust more than 388 gallons of fuel in any hour during drilling, they will be out of compliance with the 19.0 pound per hour emission limit (388 x 0.049 = 19.0).

The emission factor for these same emission units is determined through specific testing performed before each drilling season. If the same emission unit is tested the following year and the new emission factor is determined to be 0.059 pounds per gallon, then the same group of emission units will be effectively restricted to 322 gallons per hour. This type of operational limit exists for each pollutant, and the most stringent operational limit sets the overall operational limit for Shell. As long as Shell maintains their operations below the back-calculated operational rate, they will be in compliance with the emission limit.

This group of emission units will be controlled by selective catalytic reduction controls to reduce NO_x emissions. The permit requires control device monitoring including catalyst inlet temperature, urea feed rate and catalyst activity. If any of the parameters are outside the specifications set in the permit, the emission factor for NO_x from the group of emission units increases by a factor a 10 or from 0.049 to 0.49 pounds per gallon because the SCR unit is assumed to be 90% effective in reducing NO_x. The effective operational limit then becomes 39 gallons per hour to assure NAAQS are protected while the control device is not operating correctly.

Overall, Region 10 believes the permit contains terms and conditions sufficient to protect the NAAQS and that additional operational or production limits to protect the NAAQS in this permit are not necessary. The commenters have not shown why short term operating limits are a necessary addition to assure compliance with the NAAQS.

J.2 SUBCATEGORY – ADEQUACY OF $PM_{2.5}$ LIMIT

Comment J.2.a: Commenters state that the compliance demonstration for $PM_{2.5}$ leaves no room for uncertainty because modeled impacts are predicted to be at 97 percent of the 24-hour average $PM_{2.5}$ NAAQS. Region 10 must be able to demonstrate compliance with the NAAQS considering a margin of error based on the accuracies of the input data. Specifically, the commenters state that compliance demonstration must account for uncertainty in stack test data used to determine the emission factors. Since the emissions inputs for the modeling analysis are based, in general, on multiplying the applicable emission factor by the associated operating factor *(e.g.,* fuel usage rate) then the accuracy the initial modeling analysis. The commenters request that the following capacity limits be included in the permit.

Table 7: Additional Required Permit Limits: Capacity Limits

Permitted Source	**Capacity Limit**	**Compliance Demonstration**
Kulluk Generators	85%	Continuous load monitoring
Deck Cranes (all 3 units combined)	40%	Continuous load monitoring
Cementing/Logging Units	60%	Continuous load monitoring

Response K.3: There are no cementing and logging engines on the Kulluk. The capacity limits noted in the above table, with the exception of the capacity limit for cementing and logging units, were employed to calculate emission rates. The commenters have not shown why it is necessary to require Shell to limit capacity as noted in the table above. The permit requires emission testing at multiple loads to identify the worst-case operating load and the emission factor that represents that worst-case operating load. That emission factor is then used to calculate emissions for all operating loads during actual operation. This approach results in a conservative recording of emissions and obviates the need for tracking actual engine load or percentage of capacity. If Region 10 had determined that the use of load-specific emission factors to calculate and record emissions was necessary, the permit would have required load tracking. Furthermore, if Region 10 determined that it was necessary to avoid a particular operating capacity, the permit would have included limits on capacity and load tracking to confirm compliance. The permit assures compliance with emission limits without the need to limit or track load or engine capacity.

L. CATEGORY – SOURCE TESTING

Comment L.1: The commenters note that the Draft Permit does not require source testing for some emission units. Specifically, source testing is not required for the boilers and heaters, the emergency generators or the seldom-used engines on the Kulluk and its Associated Fleet, or the OSRV workboats. The commenters assert that because the Draft Permit does not specify equipment make, model, and capacity, it is critical that Region 10 require source testing for all emission sources.

Response: The source testing required under the permit covers the sources responsible for the majority of emissions. See response to comments I.3.a. The Region disagrees with the commenters that source testing is necessary or required for all permitted emission units, which include seldom used sources such as life boats and emergency equipment. In addition, in most cases, knowing the make or model of an emission unit would not influence EPA's decision to require testing because the emission factors normally represent ranges of units for any particular category of source types. Shell provided adequate information for Region 10 to apply appropriate emission factors to emission units and create enforceable emission limits. However, as discussed in response to comment I.3.a, Region 10 has imposed additional source testing requirements for incinerators and required the application of more conservative emission factors for sources not subject to source testing. For more discussion on source testing see responses to comments in I.3.a and M.2.a-c.

M. CATEGORY – MONITORING AND RECORDKEEING REQUIREMENTS

M.1 SUBCATEGORY – GENERAL

Comment M.1.a: Commenters express concern about monitoring provisions with respect to pollutants for which Shell is a synthetic minor source and request that Region 10 require monitoring of actual emissions and not just fuel usage.

Response M.1.a: The commenters have provided no information to indicate that the required monitoring of operations (e.g. fuel usage) will not be adequate. Region 10 believes that the fuel monitoring requirements and use of permit-derived and specified emission factors provide a reliable basis for determining emissions and thus compliance with emission limits. For those emission units employing air pollution control equipment, Permit Conditions F.3 and F.4 require continuous parametric monitoring – temperature, urea feed, and catalyst activity for SCR and temperature and catalyst activity for the oxidation catalyst. See responses to comments J.1.a and M.3.b. Region 10 believes the monitoring prescribed is an effective means for ensuring that the controls are working properly and achieving the required emissions reductions.

Comment M.1.b: Commenters state that, in the event actual emissions are not monitored, Region 10 should require monitoring of fuel consumption using a fuel flow analyzer device.

Response M.1.b: The Draft Permit required that a fuel flow meter be employed to continuously measure fuel combusted by each combustion source or common group of combustion sources except for the Kulluk emergency generator, heaters and boilers (all vessels), seldom used sources (all vessels), and OSRV work boats. In response to comments, Region 10 has revised the fuel monitoring requirements so that Shell is now required to use a fuel flow meter to measure fuel combusted by heaters and boilers. The remaining excepted sources are expected to generate less than 10% of NO_X emissions. For the combustion sources not equipped with fuel flow meters, the permit requires Shell to quantify fuel combusted by other means as specified in Permit Condition F.2.2.2. Specifically, Shell must measure the fuel combusted using the fuel tank sight glass, by manually measuring the amount of fuel in the tank using a graduated dip stick, or by measuring the fuel combusted using a fuel tank gauge. Shell is also required to make note of the start and end times of the activity during which the fuel is consumed (Permit Condition F.2.2.3) so that a fuel consumption rate (gal/hr) can be calculated (Permit Condition F.2.2.4). The alternative methods for measuring fuel use by the small and seldom used emission units in this case are reliable and the commenters have provided no information to indicate that the required techniques for monitoring fuel usage will not be sufficiently accurate to ensure compliance with permit requirements

Response M.1.d: Of the emission units required to be tested, only the deck cranes engines are to be tested only prior to the first season. All other engines that are to be tested will be tested prior to each of first two drilling seasons.

For those emission units that together constitute 91 percent of the NO_X emissions, the Region is requiring Shell to employ a stack test-derived emission factor to determine NO_X emissions. The emission factor is based upon worst-case emissions observed across three load conditions. For those engines for which Shell is not required to develop and employ a stack test-derived emission factor, Region 10 is revising the final the permit (Tables D.2.1 and D.2.2) in response to comments to require Shell to employ a more conservative emission factor. This emission factor is the 90th percentile value of stack test results for similar engines on the Discoverer and its Associated Fleet.

In response to comments, Region 10 has also reconsidered the 3 lb/ton NO_X emission factor for incinerators. The origin of this emission factor is AP-42. After further consideration, the Region is requiring Shell to stack test the incinerators to be installed at maximum capacity to determine PM, CO, and NO_X emission factors. This approach will better assure that the emission factor used to calculate emissions captures short-term fluctuations in emissions that could influence 1-hour ambient impacts.

M.2 SUBCATEGORY – EMISSION FACTORS

Comment M.2.a: Commenters notes that for emission units that are not subject to source testing, the Draft Permit relies on emission factors set forth in Tables D.2.1 and D.2.2. Because this Draft Permit does not specify equipment make, model, and capacity, the commenters believe that it is critical to require source testing for all permitted emission sources at the beginning of the drill season. In the absence of source testing for all emission sources, the commenters state that Region 10 must ensure that the emission factors are the overall worst-case emission factors in order to ensure adequate protection of the NAAQS, and to ensure a reasonable margin of safety in demonstrating compliance with the NAAQS and synthetic minor permit limits. Commenters add that if CEMS are not feasible, Region 10 must require more frequent stack testing (*e.g.,* at the beginning of *each* season from every source).

Response: The commenters are correct that the permit does not authorize construction and operation of specific emission units down to the make, model and capacity. However, Shell has provided Region 10 with information that identifies the general purpose of each unit or group of emission units and the expected capacities of each emission unit or group of units. As described in response to comments I.3.a and M.2.c, Region 10 is using reasonably conservative emission factors for calculating emissions from those units that are not required to be tested. Regarding the frequency of testing, if stack test results show 20% or more variability in the emission factor results from the most recent two tests, Shell is required to conduct stack tests every 2 years. If variability is less than 20 percent, testing shall be conducted every 5 years. In the absence of information suggesting otherwise, Region 10 believes that the testing schedule established in the Kulluk Permit will result in updated emission factors that, when used as required to calculate emissions, will provide a reasonable assurance of compliance.

Comment M.2.b: Commenters question whether the emission factors for the boilers and heaters in Tables D.2.1 and D.2.2 of the Draft Permit will ensure adequate protection of the NAAQS. The commenters cite to the BACT limit for boilers in the Discoverer permit as higher than the NO_X and PM emission factors used in the Draft Permit. Specifically, the NO_X and PM BACT limits in the Discoverer permit are equivalent to 26.6 lb/10^3 gal of NO_X and 3.1 lb/10^3 gal of PM, and are based on stack test data from the actual units. In comparison, the emission factors in the proposed permit for the Kulluk are 20 lb/10^3 gal of NO_X and 3 lb/10^3 gal of PM, and are based on AP-42. The commenters state that it is not reasonable to assume a lower emission rate for boilers on the Kulluk and Associated Fleet when the Discoverer permit represents what the Region determined to be the best available controls for these units. The commenters assert that Region 10 must require source-specific emission factors for these units, or revise the emission factors upward to reflect the worst-case boilers that could potentially be used onboard the Kulluk and Associated Fleet.

Response: Regarding the PM emission factors, the commenters incorrectly reference the Draft Permit's PM emission factor for boilers and heaters as 3 lb/10^3 gal; the emission factor in Tables D.2.1 and D.2.2 is 3.3 lb/10^3 gallons which is slightly higher than the boiler and heater emission factor in the Discoverer permit. The 3.3 lb/10^3 gal PM emission factor in the Kulluk Permit is also much greater than the 0.5 lb/10^3 gal emission factor Shell observed while testing the boilers on the Discoverer.[11] The emission factor is used to quantify emissions from each specific unit. Therefore, the use of a higher emission factor will result in reporting a greater amount of emissions than may in fact be emitted. The commenters have not shown how overestimating emissions jeopardizes protection of the NAAQS.

Regarding the boiler and heater NO_X emission factor, the commenter is correct that the emission factor used in the Kulluk permit is lower than the emission factor in the Discoverer permit. Stack testing of boilers made available by Shell subsequent to the setting of the Discoverer BACT limit shows an average emission factor of 13.1 lb/10^3 gal which is less than the 20 lb/10^3 gal AP-42 emission factor used in the Kulluk Permit which reflects some conservatism.[12] The Kulluk emission factor is lower than the Discoverer BACT limit for similar equipment, but is higher than available test data for a similar source. This data suggests that Shell will actually be emitting less PM than reported by employing a higher emission factor. Therefore, the commenters have not shown how the Kulluk emission factor jeopardizes protection of the NAAQS.

Comment M.2.c: Commenters question whether the emission factors for the emergency generators, seldom-used engines, and oil spill response vessel (OSRV) workboats are

[11] 0.5 x10^3 lb/gal = (3.55 x10^{-3} lb/MMBtu) x (MMBtu/1x10^6 Btu) x (131180 Btu/gal) x (1000). See June 16, 2011 email from Rodger Steen to Dan Meyer.
[12] 13.9 x10^3 lb/gal = (1.06 x10^{-1} lb/MMBtu) x (MMBtu/1x10^6 Btu) x (131180 Btu/gal) x (1000). See June 16, 2011 email from Rodger Steen to Dan Meyer.

sufficiently conservative. Because the NO_X and PM emission factors for these units are based on stack testing for Discoverer sources, the commenters doubt that the data truly reflect the worst-case emissions sources for these source types. The commenters believe that this is particularly important considering that these units are not subject to source testing requirements. The commenters note that the sources contribute between 5-10 percent of NO_X and PM emissions, with the OSRV workboats representing a significant share of these emissions. The commenters state that considering that the maximum modeled concentration for $PM_{2.5}$ is near the NAAQS (within 3% of the 24-hour average NAAQS) there is little room for uncertainty.

Response: In response to comments received, Region 10 reevaluated the NO_X and PM stack test results for the Discoverer and Associated Fleet, which Region 10 relied on to establish emission factors for similar units on the Kulluk and the Associated Fleet. To add a measure of conservatism to Shell's emission calculations for those engines which are not required to be tested, Region 10 has revised the emission factors for engines greater than 600 hp to reflect a value at least equal to the 90th percentile value for the tests conducted by Shell on the Discoverer and Associated Fleet. Kulluk Permit Tables D.2.1 and D.2.2. This change results in a 7.8 and 113 percent increase to the NO_X and PM emission factors, respectively, for engines greater than 600 hp. For engines less than 600 hp, Region 10 determined that the NO_X and PM emission factors in the permit already exceed 90th percentile values, which provides an adequate margin of safety.

M.3 SUBCATEGORY – CONTINUOUS EMISSION MONITORING

Comment M.3.a: Commenters contend that the only way to adequately ensure compliance with hourly limits is through the use of continuous emissions monitoring systems (CEMS), and assert that the Region must require the use of CEMS, or equivalent, for NO_2 compliance.

Response: As discussed in response to comment J.1.a, CEMS are an effective means of ensuring compliance with short-term emission limits, but CEMS are not the only means. Shell's planned exploratory operations are unusual as compared to other sources because the emission units consist of more than 50 engines and generators on the Kulluk and a fleet of numerous support vessels. There are practical considerations to requiring CEMS including that the emission units, control equipment, and monitoring equipment will be operating in a remote, harsh, Arctic environment, deck space on board the vessels is limited, and CEMS are expensive to purchase, maintain, and operate.

Region 10 is confident that the monitoring and recordkeeping prescribed in the permit assures compliance with emission limits.

Comment M.3.b: Commenters express support for the use of SCR controls, but are concerned about how the controls will function in Arctic conditions. The commenters note that Region 10 believes the SCR and OxyCat systems will be effective if inlet temperatures are high enough, the urea feed is operating, and the catalysts are active. Commenters explain that the proper functioning of these controls is essential to compliance with the NO_2 and PM NAAQS, and request that CEMS be used for these systems instead of weekly measurements with a portable monitoring device.

Response: Region 10's determination that the monitoring required in the permit will verify that the control devices are operating properly takes into account that the Kulluk will be operating in arctic conditions. Region 10 believes that the continuous monitoring system required by the permit will ensure the control equipment is operating properly. Temperature and urea feed will be monitored. Temperature measurements will be compared against temperatures measured during emission factor verification source testing. The weekly concentration checks using a portable monitor are not considered alternatives to CEMS, but instead serve as a verification that the control equipment is operating properly. As discussed in the Statement of Basis (at 45), weekly concentration checks should be an effective frequency for confirming whether the catalysts are still active. Temperature or concentration deviations from those measured during testing must be corrected and reported. The overall monitoring strategy is a reasonable and appropriate alternative to CEMS in this specific application. See response to comments in subcategories M.1 and M.2 and response to comment O.1.

Comment M.3.c: A commenter at the public hearing requested that Region 10 require the use of CEMS. The commenter expressed concern about self-monitoring of pollution in the OCS, and cited to limits on fuel use and the amount of waste combusted. Another commenter stated that because of uncertainties in the model, Region 10 should require installation and operation of CEMS for at least nitrogen dioxide, particulate matter and carbon dioxide.

Response: Region 10 would first like to clarify that the permit does not allow Shell to consider the amount of waste combusted in calculating emissions generated by waste incineration. The permit requires Shell to calculate emissions assuming the incinerators are operating at maximum capacity for all time periods that operation is allowed. Permit Condition D.4. Contrary to the commenter's assertion, monitoring emissions using CEMS will have no bearing on the accuracy of the new model or algorithms used by Shell. See comment J.1.a regarding the need for CEMS given model uncertainty. See comment O.1 regarding Shell self-monitoring. See comment I.1.c with respect to how fuel monitoring is an integral part of a monitoring and recordkeeping system that provides for a reasonable assurance of compliance with emission limitations.

N. CATEGORY – REPORTING REQUIREMENTS

Comment N.1: Commenters request that Region 10 add a condition to the permit requiring Shell to submit all of its monitoring results to Region 10, citing to Section 504(a) of the Clean Air Act. The commenters further request that, in light of the 120 day operating window for this permit, these submissions be made every 60 days (or twice) while the operations are occurring so that Region 10 has time to take enforcement action if a problem arises during the course of the operations.

Response: As discussed above in response to comment O.1, key compliance information will be available via EPA's ECHO website. http://www.epa-echo.gov/echo/ The public also has a right to request this information under FOIA.

Comment O.4: One commenter asked who was going to be monitoring Shell's operations and whether it is going to be self-monitoring. The commenter also asked whether there are going to be marine mammal or other observers.

Response: As discussed in response to comment O.1 above, monitoring of Shell's operations under the permit will be conducted through a combination of self-monitoring by Shell, inspections by Region 10, and the review of reports, source test data, and other information by Region 10. Marine mammal observers or other observers may be required by other regulatory programs or agreements but are not a component of compliance assurance under this Clean Air Act permit.

P. CATEGORY – AMBIENT AIR BOUNDARY

Comment P.1: Commenters contend that Region 10's decision to set the ambient air boundary at 540 meters from the center of the Kulluk is arbitrary and unlawful and conceals the true maximum impacts of Shell's emissions. The commenters state that, to comply with EPA's longstanding policy on ambient air, Region 10 must set the ambient air boundary at the hull of the Kulluk, noting that EPA has defined "ambient air" as "that portion of the atmosphere, external to buildings, to which the general public has access." The commenters state that, under EPA policy, an exemption from ambient air is available only for the atmosphere over land owned or controlled by the source and to which public access is precluded by a fence or other physical barriers, and that Shell does not own or control the area within the 540 meter radius (500 feet from the hull of the Kulluk) and it cannot effectively prevent public access. The commenters continue that Shell's proposal to implement a public access control program to "locate, identify and intercept the general public" does not constitute the fence or other physical barrier excluding the public that EPA's policy requires.

Response: Ambient air is defined as "…that portion of the atmosphere, external to buildings, to which the general public has access." 40 CFR § 50.1(e). Region 10 agrees with the commenters that EPA's longstanding interpretation is that "exemption from ambient air is available only for the atmosphere over land owned or controlled by the source and to which the public access is precluded by a fence or physical barrier." See Letter from Administrator Douglas M. Costle, EPA, to Senator Jennings Randolf, Chairman, Environment and Public Works Committee, re: Ambient Air, dated December 19, 1980. EPA has observed that "control" under this criterion means that "the source has certain rights to use of the land/property, including the power to control public access to it." Memorandum from Steven D. Page, Office of Air Quality Planning and Standards (OAQPS), re: Interpretation of "Ambient Air" in Situations Involving Leased Land under the Regulations for Prevention of Significant Deterioration, Attachment at 3, dated June 22, 2007 (Leased Land Guidance). Region 10 believes that excluding the area within a safety zone established by the United States Coast Guard from ambient air is consistent with this interpretation.

As discussed in the Statement of Basis (at p. 40), Shell modeled emissions from the Kulluk beginning 500 meters from the hull of the Kulluk and assumes that the Coast Guard will impose a safety zone of this distance around the Kulluk to exclude the public from the area in which Shell will be conducting its main operations. Shell therefore agreed that Region 10 would require as a condition of operation under the permit that Shell have in place at all times of operation as an OCS source a safety zone of at least 500 meters from the hull of the Kulluk within which the Coast Guard prohibits public access. See Permit Condition D.5 and D.6.

The conditions of the permit provide sufficient assurance that the general public will not have access to the area inside the safety zone, consistent with the two primary criteria EPA has used to determine when such an exclusion may apply. Given that the permitted activities occur over open water in the Arctic, these criteria must be adapted to some extent when applied to this environment, but they are still satisfied in this instance in a manner sufficient to effectively preclude public access from the safety zone.

Region 10 recognizes that Shell does not “own” the areas of the Beaufort Sea on which the Kulluk will be operating as might be the case for a stationary source on land. Shell has a lease authorizing the company to use these areas for the activities covered by the permit. A Coast Guard safety zone establishes legal authority for excluding the general public from the area inside the zone. EPA has previously recognized a safety zone established by the Coast Guard as evidence of sufficient ownership or control by a source over areas over water so as to qualify as a boundary for defining ambient air where that safety zone is monitored to pose a barrier to public access. Letter from Steven C. Riva, EPA Region 2, to Leon Sedefian, New York State Department of Conservation, re: Ambient Air for the Offshore LNG Broadwater Project, dated October 9, 2007 (Broadwater Letter).

To meet the second of the criteria applied by EPA and ensure the source actually takes steps to preclude public access, Shell proposed and Region 10 required as a condition of operation under the permit that Shell develop in writing and implement a public access control program to locate, identify, and intercept the general public by radio, physical contact, or other reasonable measures to inform the public that they are prohibited by Coast Guard regulations from entering the area within 500 meters of the hull of the Kulluk. Region 10 believes that, for the overwater locations in the arctic environment at issue in this permitting action, such a program of monitoring and notification is sufficiently similar to a fence or physical barrier on land such that the area within the Coast Guard safety zone qualifies for exclusion from ambient air. See Broadwater Letter at 2.

Shell therefore appropriately excluded the area within 500 meters of the hull of Kulluk from the source impact analysis it conducted to meet the requirements of the applicable CAA regulations.

Comment P.2: Some commenters contend that Region 10's approach to setting the ambient air boundary for the Kulluk is inconsistent with the approach Region 10 took in setting the ambient air boundary for Shell's Discoverer drillship in previous determinations. The commenters state that, when Shell initially applied for air permits for the Discoverer drillship, the company's application materials included an ambient air boundary of 900 meters and that Shell assumed that the ambient air would begin at this distance because it had "submitted a request to the US Coast Guard, for issuance of a safety exclusion and equipment protection zone surrounding the Discoverer . . . ." Nevertheless, the commenters state, in issuing permits to Shell for the Discoverer drillship in 2010, Region 10 required Shell to model impacts from the hull of the Discoverer, outward, yet Region 10 is now indicating that it will allow Shell to model impacts for the Kulluk starting 540 meters from the center of the Kulluk. The commenters allege that if Region 10 were to recognize that the edge of the hull is the appropriate boundary, Shell has not demonstrated that its operations will not cause a violation of air quality standards in the "ambient air" and that Shell has in fact stated that maximum modeled impacts occur on or near the 540 meter boundary, indicating likely greater impacts inside of that boundary.

Response: The commenters are correct that Shell's February 2009 application for an OCS/PSD permit for operations for the Discoverer in the Chukchi Sea did request an ambient air boundary based on a Coast Guard safety zone. Shell later withdrew that request and the 2010 Permits for the Discoverer drillship issued by Region 10 therefore did not base the ambient air boundary on a Coast Guard safety zone, but instead assumed that ambient air began at the hull of the Discoverer. In response to the remand from the Environmental Appeals Board, Shell subsequently submitted modeling for the Discoverer demonstrating compliance with the NAAQS based on a Coast Guard safety zone and the final permits issued by Region 10 for the Discoverer in response to the remand require Shell to obtain a Coast Guard safety zone as a condition of operation under the permits. See Supplemental Response to Comments for the Discoverer Drillship permits, dated September 19, 2011, at 41.

Similarly, in its application for a permit for the Kulluk, as discussed in the Statement of Basis (at p. 40), the application materials submitted by Shell modeled emissions from the Kulluk beginning 500 meters from the hull of the Kulluk and assumes that the Coast Guard will impose a safety zone of this distance around the Discoverer to exclude the public from the area in which Shell will be conducting its main operations. The permit therefore authorizes operation only if the Kulluk is subject to a currently effective safety zone established by the Coast Guard. Because the area within the safety zone is not considered ambient air, demonstrating compliance with the NAAQS within that zone is not required. Thus, Region 10 acted consistently with Shell's application materials for the Discoverer permits, Shell's application materials for this permit, legal requirements, and EPA guidance in determining the ambient air boundary based on a Coast Guard safety zone. See also response to comment P.1.

Comment P.3: Several commenters express concern that Shell had not provided and Region 10 has not required an analysis showing what air quality would be within the safety zone and state that the size of the zone is arbitrary. Commenters assert that workers within that zone will not be protected and that the federal agencies are not working together to ensure healthy air. Commenters state that residents of the North Slope serve as marine mammal observers and members of the communications team on the drillship and will be subjected to below standard air quality. These commenters contend that emission levels throughout the OCS, including within the safety zone, should meet lawful levels and express concern that winds would take air pollution farther than 500 meters from the ship. Commenters state their concern for what this decision means for air quality on the OCS where local communities hunt and fish.

Response: Region 10's understanding is that Marine Mammal Observers will be employees of Shell or Shell contractors. 2012 Revised Camden Bay Exploration Plan at 11-4 (Marine Mammal Observers provide an opportunity for local hire). Under established EPA policy, contractors, subcontractors, and employees that are expressly granted access to a site by the entity with control over the site are not considered the general public vis-à-vis that entity, but instead are considered "business invitees." See Memorandum from Stephen D. Page, Director OAQPS, re: Interpretation of "Ambient Air" in Situations Involving Leased Land Under the Regulations for Prevention of Significant Deterioration (PSD), dated June 27, 2007, Attachment at p. 5. Their presence within the Coast Guard safety zone thus does not deprive that area from qualifying for exclusion from ambient air. See also response to comments P.1 and P.4.

Comment P.4: Commenters contend that allowing OCS sources to establish ambient air boundaries in the Arctic based on safety zones raises concerns regarding the cumulative impacts to offshore air quality that several such operations with ambient air quality boundaries would have on air quality. The commenters cite to a Government Accounting Office Report, GAO, EPA's Ambient Air Policy Results in Additional Pollution, July 1989 (available at: http://archive.gao.gov/d26t7/139340.pdf) and assert that that EPA has been subject to scrutiny for creating ambient air boundaries in the first instance because they allow for greater air quality deterioration. The commenters ask Region 10 to explain why this boundary works in the Arctic and how Region 10 arrived at the decision to allow more pollution instead of less, particularly in light of the heavy use of offshore areas by subsistence communities. Commenters expressed concern about what Region 10's decision means for air quality on the OCS where people hunt and fish.

Response: Safety zones are established by the Coast Guard based on safety considerations, not air quality considerations. See, e.g., 75 Fed. Reg. 803 (January 6, 2010) ("The purpose of the temporary safety zone is to protect the DRILLSHIP from vessels operating outside normal shipping channels and fairways. Placing a temporary safety zone around the DRILLSHIP will significantly reduce the threat of allisions, oil spills, and releases of natural gas, and thereby protect the safety of life, property, and the environment")(capitalization in original). However, because such a safety zone combined with Shell's public access control program has the effect of restricting the general public's access to the relevant area, as discussed in response to comment P.1, Region 10 believes the presence of a safety zone supports excluding the area inside the zone from ambient air for air quality purposes consistent with prior EPA interpretations of its regulations.

The GAO report cited by the commenters focused primarily on concerns with land acquisition to increase the size of the ambient air boundary and thus as a pollution control technique, which is not implicated in the application for and the establishment of a Coast Guard safety zone based on safety considerations. As discussed above in response to comment P.1, EPA has previously determined that a Coast Guard safety zone is an appropriate basis for establishing an ambient air boundary within which demonstration of compliance with the NAAQS is not required. As discussed in Sections 4 and 5.4 of the Statement of Basis and the Technical Support Document, emissions under this permit are not expected to cause or contribute to violations of the NAAQS in any area that constitutes ambient air, including in areas where local communities regularly conduct subsistence activities. With respect to cumulative impacts, please see the responses to comments in Category Y.

Comment P.5: Commenters request that, if the ambient air boundary remains in place, Region 10 examine options for requiring monitoring at 500 meters from the Kulluk for the first two weeks of the drilling season. The commenters state they are not aware of any reasons why it would not be technologically feasible to operate monitoring equipment from a moored vessel.

Response: Region 10 believes that the background monitoring data that have been collected in conjunction with the air quality modeling conducted to support this permit action adequately demonstrates that emissions under the permit will not cause or contribute to a violation of the NAAQS. The emission limits and associated monitoring, recordkeeping, and reporting requirements in the permit are adequate to verify that the NAAQS will not be exceeded and Region 10 therefore does not believe the additional monitoring requested by the commenters is warranted. Given the challenges of conducting ambient air monitoring in harsh, remote arctic conditions, Region 10 does not believe it is appropriate to require monitoring to be conducted on a vessel at the ambient air boundary. Region 10 believes collection of background air quality data within a closer proximity to a community provides more beneficial information on potential health-based exposure than a monitor located well offshore.

Q. CATEGORY – GENERAL COMMENTS ON AMBIENT AIR QUALITY ANALYSIS AND SUPPORTING DATA

Comment Q.1: Commenters state that the statute and applicable regulations dictate that Region 10 may not issue Shell a Title V operating permit unless it "includes conditions that will assure compliance with all the requirements of [the Clean Air Act] at all authorized locations, including, but not limited to, ambient standards and compliance with any applicable increment or visibility requirements . . . ," citing to 42 U.S.C § 7661c(e) and § 7661c(a); 40 CFR §§ 71.2, 71.6(a)(1), 71.6(e)(1). These commenters contend that Shell has not demonstrated its ability to comply with all applicable requirements and that Region 10—which premised the draft permit conditions on Shell's modeling assumptions—has not established adequate permit conditions sufficient to guarantee compliance.

data to support its permit application and air quality analysis. See also response to comment T.1.

Shell only used the July through November portions of the meteorological data since they are only authorized to operate within this period. See Appendix W, Table 8.2, fn. 2 (discussing that if a source is subject to an enforceable limitation on hours of operation, only the hours of authorized operation are to be modeled with emissions from the source). Because the meteorological data is only used in connection with modeling emissions from the permitted source, meteorological data collected from times other than during the periods of authorized operation are not used in the modeling analysis. Region 10 believes that even if Shell did not have meteorological data for the periods they did not model (i.e., December through June), Shell would still have data of sufficient duration for purposes of Section 8.3.1.2(b) of Appendix W because the data collection period covers one year's worth of the period of authorized operation. In this case, five months worth of data covering July 1 through November 30 is one year of data within the meaning of that section. Since the permit only authorizes operations from July 1 to November 30, emissions and hence contributions to ambient air quality, will both be zero during the remainder of the year.

Comment T.3: Commenters state that the meteorological data Shell has collected do not meet the standard set by EPA's guidelines for the required time period because the buoy data only cover the period from mid-August to mid-October, meaning that Shell has no over-water data for July or November.

Response: Shell deployed the instrumented buoys during the open-water periods. Shell could not collect "over-water" data during those periods when there was no over-water data to be collected (*i.e.*, during those periods where there is no open water due to the presence of ice). It is important to note that while AERMOD-COARE requires the air-sea temperature difference and relative humidity data collected by the buoys, the Guideline version of AERMOD – which Shell used to estimate ambient impacts when sea ice is present – does not. Therefore, Shell collected the meteorological parameters needed by each model for those periods that the given model was used. Because Region 10 considers the data to be site specific, one year's worth of data is sufficient to support Shell's analysis. See the response to comments T.1 and T.3.

U. CATEGORY – BACKGROUND AIR MONITORING DATA

Comment U.1: Commenters question Region 10's initial assumption that the use of onshore data is "conservative" because "onshore monitoring stations will be influenced by local sources that are not present in the vicinity of Shell's offshore operations." The commenters explain that emissions from Shell's operations will be influenced by local sources which include the associated vessels that are stationed more than 25 miles from the drillship, barge and shipping traffic in the Arctic OCS, as well as scientific research vessels and accompanying ice breakers and other vessels. The commenters conclude that the presence of these local sources of offshore emissions undermines expectations that onshore data is automatically conservative. The commenters assert that this is an important consideration because the most conservative background data was not necessarily used for the modeling.

Response: Region 10 agrees that emissions from vessels operating in the vicinity of Shell's exploratory operations will contribute to the air pollution levels in the area. However, Region 10 disagrees that this would mean that the concentrations measured onshore would not be conservative for offshore locations where Shell will be operating under the permit. First, the Kulluk is a portable source and will be at different locations during any drilling season and during subsequent drilling seasons. It is not possible to determine where and for how long the Kulluk will be operating near other vessels in the area so trying to determine the background contribution of vessels operating near the Kulluk would be difficult. Second, other vessels will also be moving in relation to the Kulluk so their contribution to the ambient levels in the immediate vicinity of the Kulluk when it is at a drillsite will be transitory. The effect of these two overlapping scenarios, along with the statistical form of the relevant short-term NAAQS, is that the contribution to background concentrations from vessel activity at the location of the Kulluk's maximum impacts is expected to be minimal, if anything. The concentrations measured by the onshore background monitoring locations, however, are regularly impacted by nearby sources, including mobile sources and other fuel combustion sources, such as the villages' diesel generators. The concentrations at on onshore monitoring locations that are regularly impacted by nearby sources are expected to be significantly higher than the concentrations at a drillsite that would be occasionally impacted by passing vessels. Region 10 has therefore determined that the concentrations measured onshore at monitoring sites are conservatively representative of concentrations offshore at the project locations.

Comment U.2: Commenters assert that there is significant confusion in the permit record regarding the datasets used for different background concentrations, most notably the datasets for background concentrations of NO_2. The commenters refer to the air quality impact analysis for the draft permit in which Region 10 proposes using NO_2 data from the Prudhoe Bay A-Pad monitoring site as representative of background concentrations for both the 1-hour and annual NAAQS. The commenters also refer to Region 10's June 23, 2011 determination of background concentrations for the Beaufort Sea which states: "Since some of the lease blocks for the Kulluk permit are very near to the Prudhoe Bay area it was deemed appropriate to utilize the Deadhorse $PM_{2.5}$ data set for determining a background value and CCP for NO_2 and SO_2." The commenters contend that there is no further discussion about the NO_2 dataset from the Prudhoe Bay CCP monitoring site, and that the Region must use the CCP data if they represent a more conservative background dataset. The commenters state that annual average NO_2 concentrations from the CCP site are one and a half times higher than those monitored at the A-Pad location, and conclude that it is like that the hourly average concentrations are also higher. The commenters conclude that Region 10 must use the dataset with the highest monitored 1-hour average and annual average NO_2 concentrations, particularly for the1-hour average NAAQS if the modeling will be based on an analysis of data paired in time.

Response: As Region 10 explained on page 29 (footnote 7) of the Technical Support Document, the monitoring site ultimately used for the NO_2 analysis (A-Pad) is different than the site recommended in the June 23, 2011 memo (CCP). The requirements for the background data used in an air quality modeling analysis are described in Section 8.2 of the Guideline on Air Quality Models (40 CFR Part 51, Appendix W). There is no requirement that the data be conservative and there is certainly no requirement that it must be the most conservative of available data. In this case, there is no offshore ambient air data, so an onshore site was used to represent the background concentrations expected within the vicinity of the Kulluk lease blocks. However, as discussed below and in the response to comment Y.2, the onshore monitoring site used in this analysis is expected to be impacted by similar natural and distant man-made sources, but more heavily impacted by the local sources than what would likely occur at the project locations. As such, Region 10 believes that it is conservatively representative of the background concentrations at the project location.

The requirements for the background data used in an air quality modeling analysis are described in Section 8.2 of the Guideline on Air Quality Models (40 CFR Part 51, Appendix W). Section 8.2.2.b and c provide:

> b. Use air quality data collected in the vicinity of the source to determine the background concentration for the averaging times of concern….
> c. If there are no monitors located in the vicinity of the source, a "regional site" may be used to determine background. A "regional site" is one that is located away from the area of interest but is impacted by similar natural and distant man-made sources.

The A-Pad and CCP monitoring sites are located in close proximity to the onshore sources in the Prudhoe Bay area so both are conservatively representative of offshore concentrations at the Kulluk lease blocks. Background concentrations from both locations reflect contributions from the onshore sources in varying amounts depending upon their location with respect to those onshore sources. The CCP monitor is located within 100-meters of the CCP facility, which has just over 14,000 tpy of potential NO_x emissions. The adjacent CGF facility (which is part of the CCP/CGF stationary source) has almost 11,000 tpy of potential NO_x emissions. The air quality impacts of these facilities are also strongly dominated by downwash of the plumes, which leads to the maximum impacts occurring in the immediate area. This conclusion can be deferred from existing documentation regarding this monitoring effort and source. For example, the Quality Assurance Project Plan (QAPP) for the CCP and A Pad monitoring stations states:

> The CCP monitoring site is located between the Central Compressor Plant and the Central Gas Facility; approximately 100 meters west and southwest of the CCP [reference to figures]. This site is located at or near the point identified by dispersion modeling as the maximum NO_2 impact receptor…"

Quality Assurance Project Plan for the Prudhoe Bay Unit Facilities Ambient Air and Meteorological Monitoring Project, February 2011, at 27.

As another example, in the Technical Analysis Report (TAR) issued for Construction Permit AQ0270CPT04 (CGF) and AQ0166CTP04 (CCP), ADEC stated, "The maximum cumulative impacts (for the given H_2S and fuel-sulfur assumptions) occur in the CGF/CCP near-field" (Exhibit B, pg 14). While the statement related to H_2S related impacts, the same finding would be true for NO_x impacts since combustion-related plumes do not vary by pollutant.

The CCP monitoring station was therefore sited close to the CCP/CGF facilities in order to capture the maximum impact of these facilities. As such, CCP data would be overly conservative for representing the background concentrations at offshore locations. Even the A-Pad monitoring site, which Region 10 relied on, is expected to be a conservative representation of the background air quality concentration at the offshore locations where Shell will be operating.

Comment U.3: Commenters express concern about the use of different background concentrations for the Shell Beaufort Discoverer and Shell Kulluk permits, and express support for use of the Kulluk permit datasets which the commenters state are more conservative. The commenters provided the following table to show the difference in background values between multiple permits:

Table 8: Information from "EPA Region 10 Determination of Appropriate Background Values for the Chukchi and Beaufort Sea OCS Permits" (June 23, 2011)

	Shell Kulluk	**Shell Discoverer Beaufort**	**ConocoPhillips Jackup Rig**	**Shell Discoverer Chukchi**
PM2.5 24hr	Deadhorse	Badami	Wainwright permanent	Wainwright permanent
PM2.5 annual	Deadhorse	Badami	Wainwright permanent	Wainwright permanent
PM10 24 hr	Prudhoe Bay CCP	Prudhoe Bay CCP (Same as Kulluk)	Wainwright permanent	Wainwright permanent
NO2 1 hr	Prudhoe Bay A Pad	Badami	Wainwright temporary	Wainwright temporary
NO2 annual	Prudhoe Bay CCP (text) Badami (chart)	Badami	Wainwright temporary	Wainwright temporary
SO2	Prudhoe Bay CCP	SDI	Wainwright temporary	Wainwright temporary
CO	SDI	SDI (same as Kulluk)	Wainwright temporary	Wainwright temporary
O3	No information	No information	No information	No information

commenters also request a similar comparison of the recent air quality monitoring data collected from Nuiqsut.

Response: Even though a QAPP was approved for the Kaktovik monitoring station in May-June 2011, the site did not begin collecting data until July 1, 2011. The site does not have data yet for a complete drill season or a calendar year, so there is not enough data to use in a NAAQS analysis. Only a few weeks of data would have been available at the time Region 10 proposed the Draft Permit even if it had been submitted to Region 10 for review. With respect to monitoring data from a site operated by ConocoPhillips at Nuiqsut, this data has not be submitted to Region 10 for review or use in a regulatory analysis.

Comment U.6: Commenters express concern that the most conservative data from the North Slope is not being used. The commenters cite as an example data from Point Lay which the commenters characterize as showing much higher background levels of certain pollutants.

Response: Both Wainwright and Point Lay are on the Chukchi Sea, not the Beafort Sea. The data that was used in the Chukchi Sea (presumably for the Discoverer PSD permits) is not relevant to the air quality impact analysis for the Draft Permit, which only authorizes operations in the Beaufort Sea. This comment appears to relate to the recently issued permit for the Discoverer and, as such, Region 10 is not responding to it here.

V. CATEGORY – AIR QUALITY ANALYSIS FOR 1-HOUR NO_2 NAAQS

V.1 SUBCATEGORY – IN GENERAL

Comment V.1.a.: Commenters state that the new 1-hour NO_2 NAAQS was set at a level recognizing the substantial body of scientific evidence demonstrating that the previous annual NO_2 NAAQS was alone sufficient to protect human health. The commenters also state that short term spikes in NO_2 concentrations are associated with a range of negative human health effects. The commenters note that the new 1-hour NO_2 NAAQS includes a new "form" for the standard that is based on the 3-year average of the 98th percentile of the yearly distribution of 1-hour daily maximum concentrations. The commenters conclude that Shell has not demonstrated that it will comply with the 1-hour NO_2 NAAQS and that Region 10 therefore cannot issue the permits.

Response: As discussed in Section 4 of the Statement of Basis and in the Technical Support Document, when operating in compliance with the terms and conditions of this permit, emissions authorized under the permit will not cause or contribute to a violation of the NAAQS, including the NO_2 NAAQS. The NAAQS are health-based standards, set at a level to protect public health with an adequate margin of safety, including sensitive populations such as children, the elderly, and asthmatics.

Comment V.1.b: Commenters acknowledge EPA's new "data handling conventions for NO_2" whereby NAAQS compliance is "based on the 3-year average of the 98th percentile of the yearly distribution of 1-hour daily maximum concentrations," but assert that the new data handling convention is specific to determining "area-wide" compliance with the revised NAAQS. The commenters contend that there is no basis in the Clean Air Act or the new standard itself for the permitting approach that Region 10 has adopted here which allows a proposed new source to discount its highest projected impacts. The commenters conclude that such an approach ignores both the importance of the absolute value of the NAAQS standard—which they assert must be set at the requisite level to protect human health—as well as the Title V requirement that a proposed permit include sufficient conditions to prevent a NAAQS exceedance, citing to CAA § 165(c) and (e), 40 CFR §§ 71.2, 71.6(c)(a)(1) and 71.6(e)(1).

Response: The commenters appear to be arguing that a source must demonstrate that the impact of its emissions does not exceed the level of the NAAQS. Region 10 disagrees with this position.

Shell's modeling analysis for the 1-hour NO_2 standard is consistent with the form of the NAAQS and EPA guidance on demonstrating compliance with the 1-hour NO_2 NAAQS. See Memorandum from Stephen Page, OAQPS, re: Guidance Concerning the Implementation of the 1-Hour NO_2 NAAQS for the Prevention of Significant Deterioration Program, dated June 29, 2010 (June 2010 1-hour NO_2Modeling Guidance); Memorandum from Tyler Fox, OAQPS, re: Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-Hour NO_2 NAAQS, dated March 1, 2011 (March 2011 1-Hour NO_2 Modeling Guidance). The commenters have provided no specific information showing how Shell's approach "discount[ed] its highest projected impacts" in a manner that is inconsistent with the form of the NAAQS.

Although it is true that the modeling showed individual 1-hour impacts higher than the 100 ppb (188 $\mu g/m^3$) level of the 1-hour NO_2 NAAQS, the 98th percentile point of the annual distribution of daily maximum 1-hour concentrations does not exceed 100 ppb (188 $\mu g/m^3$) at any location that constitutes ambient air. The commenters cite to CAA § 165 and 40 CFR §§ 71.2, 71.6(c)(a)(1) and 71.6(e)(1) in support of their argument that the permittee must demonstrate that the level of the NAAQS is not exceeded. The cited statute, however, applies to issuance of PSD permits, not to Title V permits such as this, and the regulation promulgated by EPA to implement that statutory provision plainly states that a source must demonstrate that it will not cause or contribute to "a violation of" any NAAQS, and does not refer to "an exceedance." See 40 CFR § 52.21(k)(1). The Title V regulations cited by the commenters do not support the commenters position, and the commenters have provided no other information to support their contention that, for an air quality analysis submitted in connection with a Title V permit application or an Alaska minor source permit application, the applicant must establish that they will not cause or contribute to ambient concentrations that exceed the level of a NAAQS.

Comment V.1.c: Commenters state that Shell has understated maximum 1-hour NO_2 impacts by failing to accurately calculate the multiyear average of the 98th percentile of the annual distribution of daily maximum 1-hour values. The commenters continue that EPA estimated that, when evaluating the measured concentrations for a year's worth of monitoring data, the 98th percentile would be equivalent to the 7th or 8th highest daily maximum for the 365-day period. In calculating its compliance with the 1-hour NO_2 standard, the commenters assert, Shell selected the 8th highest daily maximum but that this is an underestimate of the true 98th percentile associated with its operations because Shell's drilling season is only 120 days long, and it modeled only that many days. The commenters conclude that selecting the 8th highest daily maximum from 120 days corresponds roughly to the 93rd percentile, not the 98th percentile, and that Shell has therefore failed to demonstrate that its proposed operations will not cause a violation of the NAAQS.

Response: Region 10 continues to believe that the air quality analysis performed by Shell in connection with the 1-hour NO_2 NAAQS is consistent with 40 CFR Part 51, Appendix W (Guideline on Air Quality Models) and EPA guidance for implementing the 1-hour NO_2 NAAQS. In practice, a modeling analysis performed for the 1-hour NO_2 NAAQS can generally be summarized as a three step process involving the collection and preparation of appropriate background data, pairing background data with modeled impacts, and finally comparing the resulting total concentration to the NAAQS. Because the form of the 1-hour NO_2 NAAQS is the 3-year average of the 98th percentile of the daily maximum 1-hour averages, there can be a certain number of hourly values each year that exceed the NAAQS threshold. In Shell's analysis, two years of monitoring data are available and one year of modeled results are available and were used in the modeling analysis.

For the first step, Shell calculated diurnal hourly background values (that is, a background value for each hour of day) for the drilling season (a 5 month period) using background monitoring data collected in 2009 and 2010 for the Beaufort Sea. Shell took all available hourly NO_2 data during the drilling season period for a particular hour and calculated, for that hour, the 98th percentile NO_2 concentration recorded for that hour in each of the two years of available monitoring data. 40 CFR Part 50, Appendix S, Table 1 prescribes the rank associated with the 98th percentile value based on the number of available valid samples within a period.[15] Following this procedure for determining a 98th percentile of the monitoring data for each hour, Shell used a 2nd, 3rd or 4th high, depending on the number of available data points, to determine the hourly 98th percentile value (*i.e.*, if 153 hourly values were available, the 4th high represented the 98th percentile for this hour, while a data set with only 100 hourly values would use the 2nd high to represent the 98th percentile for that hour). For each hour, the 98th percentile result for each year is averaged and this average hourly value is then used to pair with the respective modeled result for that hour. The result of this approach is a generic day's worth of NO_2 background data that represents the 98th percentile value for each hour in a drilling season. Results of this procedure are found in a spreadsheet entitled "Shell_Diurnal_NO2_Background_Kulluk_04182011-stats.xls" submitted by Shell's consultant on May 4, 2011. The spreadsheet was part of a larger submittal transmitted under a technical memorandum entitled "UPDATES TO AIR QUALITY IMPACT ANALYSIS – KULLUK DRILLSHIP." Region 10 determined that this approach

[15] The 1-hour NO_2 standard is based on the 98th percentile (8th highest) of the annual distribution of maximum daily 1-hour values. March 2011 1-Hour NO_2 Modeling Guidance at 1, fn. 1.

followed EPA guidance and provides a representative monitored hour by season diurnal profile for the drilling season.

For the second and third steps, Shell paired, for each modeled hour and receptor location (again, over a 5 month period), the result of the modeled impact with the hourly monitored background value for that hour calculated in step 1 above. The highest hourly total concentration (paired modeled and monitored impact) in a calendar day was then calculated, and the 8^{th} highest paired modeled/monitored impact for each receptor was used to compare with the NAAQS. Using the 8^{th} highest value that occurred over the 5 month drilling season is appropriate because emissions from Shell's operations during periods other than the drilling season are zero (so the total concentration consists only of the background value, yet the form of the standard is a 3-year average of the 98^{th} percentile daily 1-hour maximums). The time period during which no drilling will be occurring is therefore considered in determining the annual 98^{th} percentile value for each year and the 3-year average of annual 98^{th} percentile values, but, because there will be no emissions from Shell's operations in the total concentration during the periods of no drilling, the 8 highest total concentrations for a given year are not predicted to occur during this period, but instead are predicted to occur during the drilling season for that year. In other words, although there are 365 days used in the 98^{th} percentile calculation, the majority of these days (7 months worth) will have no Shell impacts because Shell is not permitted to operate outside of the 5 month drilling season. Because of this, the 8 highest values, and thus the 98^{th} percentile value, are all days that fall within the drilling season. The commenters have not identified any day outside of the drilling season that would have had a higher total concentration than the 8^{th} highest total concentration during the drilling season.

In summary, Region 10 disagrees with the commenters that selecting the 8^{th} highest daily maximum from 120 days corresponds to the 93rd percentile, not the 98^{th} percentile. For the monitored background data, Shell was required to use a 2^{nd}, 3^{rd}, or 4^{th} high value depending on the available data because the monitored data relied on in the modeling analysis consisted of less than a year (approximately 5 months). For the modeled impacts, which are paired with the monitored data, however, Shell appropriately used the 8^{th} high modeled-plus-background value, which is the 98^{th} percentile among the 365 days of the year (the timeframe averaged as part of the standard) and evaluated this value against the NAAQS. This approach is consistent with EPA guidance for the 1-hour NO_2 standard. March 2011 1-Hour NO_2 Modeling Guidance at 2 (discussing the procedure for demonstrating compliance with the NAAQS) and 17-21 (describing the appropriate methodology for incorporating background concentrations into a 1-hour impact analysis).

It is important to note that there are several conservative assumptions that will likely result in substantially lower total concentrations than those predicted by the model. One such assumption is that the modeling assumed the Kulluk will be located at the same drill site for the entire three year period considered in the modeling analysis for the 1-hour NO_2 standard. In the more likely event that Shell will be operating at a different drill site in each of the three years (and possibly more than one drill site in each year), the expected 3-year average of the 98^{th} percentile concentrations at each drill site would be much lower. Another conservative assumption underlying the modeling analysis is the fact that the background data used to represent offshore conditions was collected onshore, where it is influenced by local sources. See response to comments in Category U.

Comment V.1.d Commenters contend that Region 10 has failed to ensure that Shell's modeling assumptions reflect actual operating conditions because Shell does not establish that its modeling captures all realistic combinations of allowable operations, background levels, and meteorological conditions that may result in maximum impacts. In modeling its effect on 1-hour NO_2 standards, the commenters assert, Shell assumes a perfect choreography of closely-timed events and favorable conditions and lines up events and conditions in an unrealistically precise manner by varying—for every hour of its proposed 2,880 hours of operation— meteorological conditions, background concentrations, and fleet operations. This method of modeling operations, the commenters continue, is therefore likely not representative of actual operating conditions, does not capture a full, realistic range of potential operations and conditions, and is vulnerable to missing maximum impacts. Thus, the commenters conclude, Shell has not demonstrated compliance with applicable standards, including the 1-hour NO_2 NAAQS. For example, the commenters state that Shell has used day to day meteorological conditions from 2009 and 2010 to determine the future positions of its ships hour by hour, rotating its vessels in accordance with the wind direction from those prior years, but that it is unlikely the wind will behave in the same manner on a daily basis in future years and that by shifting the position of its vessels, Shell could be diluting concentrations in a way that masks even greater impacts. For example, the commenters continue, Shell will miss maximum 24-hour $PM_{2.5}$ impacts if Shell assumes the ships will be shifting position every hour when in fact the wind is steady and the vessels operate in one position. The commenters assert that Shell's modeling should be based instead on scenarios in which meteorological conditions, background concentrations, and vessel operations combine to maximize impacts and reproduces the full range of operating scenarios and impacts.

Response: Region 10 believes the combinations of operating conditions modeled by Shell accurately reflect the expected emissions that will occur with the permitted operations. It is not possible to model all potential combinations of emissions scenarios, thus the need to select conservatively representative emissions scenarios that conform to the permitted emission rates.

Region 10 carefully reviewed the emissions scenarios and required several model iterations using two different drilling start times such that all hours during the drilling season are accounted for. While Region 10 acknowledges the actual operations will not exactly mirror what was modeled, the approach taken is expected to conservatively represent permitted emissions during a drilling season. The comment does not identify any realistic range of potential operations and conditions that have not been captured in the conservatively representative emissions scenarios used in the modeling supporting these permits.

Region 10 also disagrees that there is a "perfect choreography of closely-timed events and favorable conditions" and that Shell's modeling "lines up events and conditions in an unrealistically precise manner." The emissions sequences used in the modeling reflect the general sequence of drilling operations as they would be expected to occur. Obviously, the sequence will not exactly mirror that modeled but the general order is correct and reflective of what is allowed in the permit. The other conditions the commenters discuss, such as lining up meteorological and background values, are reflective of actual collected data which, when coupled with conservative assumptions, such as orienting the Associated Fleet with hourly modeled wind direction and using emission release characteristics based on actual meteorological conditions, result in a conservative analysis which has demonstrated compliance with the NAAQS. The meteorological data relied on by Shell adequately reflects representative meteorological conditions. Applicants are not required to demonstrate compliance under non-representative conditions. The commenters present a hypothetical concern regarding persistent wind directions, but they do not provide information showing that this concern is realistic and, if so, whether it is a condition that was not represented in the modeled data set. Moreover, the wind roses provided in Shell's application shows the frequency of winds from any given direction. See Permit Application Supplement, Figure 3-5, at 61. As shown by these figures, the meteorological data used by Shell contains frequent easterly winds. Therefore, the concern expressed by the commenters was in fact, addressed in Shell's modeling analysis.

Moreover, as discussed in response to comment V.1.c and V.2.b, there are several other conservative assumptions underlying the modeling that are not related to the operating scenarios. These assumptions, in conjunction with the reasonable operating scenarios modeled by Shell, make it very unlikely that actual impacts will in fact cause or contribute to a violation of the NAAQS.

Comment V.1.e: Commenters state that Shell has not demonstrated that it will comply with the health based standards for NO_2 and that Shell's own modeling shows that its operations could cause pollution levels to reach 81% of allowable concentrations of NO_2 The commenters also note that high levels can cause breathing problems, particularly asthma, and impacts the elderly and small children.

Response: See response to comment V.1.a. By stating that Shell's modeled emissions (which in this case include background concentrations) could cause pollution levels to reach 81% of allowable 1-hour concentrations of NO_2, the commenters appear to concede that emissions from Shell's proposed operations will not cause or contribute to a violation of the 1-hour NO_2 NAAQS.

Region 10 also notes that in its permit application Shell requested an aggregate limit for the three Kulluk deck cranes. However, the modeling initially provided by Shell did not support aggregate limits. During the public comment period, Shell again requested an aggregate limit for the Kulluk deck crane engines and provided modeling to support this request. This modeling, which was reviewed by Region 10, showed a minimal increase in the maximum modeled concentration to 86% of the 1-hour NO_2 NAAQS. This change does not increase the source's potential to emit. For additional discussion of the modeling and revised limit see response to comment HH.4.

V.2 SUBCATEGORY – BACKGROUND DATA FOR 1-HOUR NO_2/ USE OF PAIRED DATA

Comment V.2.a: Commenters note that Shell used day-to-day meteorological conditions from 2009 and 2010 to determine the future positions of its ships, rotating its vessels in accordance with wind direction from those prior years. The commenters state that the wind will not behave in the same manner on a daily basis in future years, and that by shifting the position of the vessels, Shell could be diluting concentrations in a way that masks even greater impacts. As an example, commenters state that Shell would miss maximum 24-hour $PM_{2.5}$ impacts if it assumes the ships will be shifting position every hour, when in fact the wind is steady and the vessels operate in one position.

Response: While Region 10 acknowledges the actual operations will not exactly mirror what was modeled, the approach taken is expected to conservatively represent permitted emissions during a drilling season. The commenters present a hypothetical concern regarding persistent wind directions, but they do not present information showing that this concern is realistic and, if so, whether it is a condition that was not represented in the modeled data set. See response to comment V.1.d.

Comment V.2.b: Commenters state that Shell has understated 1-hour NO_2 impacts by using background data in a manner that understates health and environmental risks and does not demonstrate compliance with the 1-hour NO_2 NAAQS because Shell has used background ambient air data in a manner that systematically understates the impact of its operations. The commenters contend that Shell has neglected to use the highest background pollution levels measured in the vicinity of its proposed operations and has instead adjusted background ambient air data by using multiyear averages of the 98th percentile background concentrations for each hour of the day. The commenters argue that Shell has made two downward adjustments: in addition to discounting the highest concentrations caused by its operations, Shell has assumed that such concentrations will not occur at a time when background concentrations are at their highest observed levels. The commenters contend that this has the effect of "compounding" the 98th percentile adjustment, thereby understating the true maximum impacts that may occur as a consequence of Shell's operations. Although acknowledging that EPA has indicated that this technique may be appropriate in some circumstances, the commenters contend that this guidance is not consistent with the 1-hour NO_2 standard itself, which they claim is evaluated with a single adjustment for the 98th percentile, and that even that adjustment may not be applicable to this permitting action. According to the commenters, Shell's manner of selecting 1-hour NO_2 background data for use in its model disregards the highest possible background levels, underestimates the true maximum impact of Shell's operations, and fails to demonstrate that it will not cause a violation of air quality standards.

Response: The 98th percentile of the monitored background concentrations based on the Deadhorse monitors along the Beaufort Sea is a conservative estimate of the background levels at the location of the 98th percentile of the modeled concentrations, and therefore provides a conservative estimate of cumulative NO_2 impacts from Shell's operation. Using background concentrations from onshore monitors is a conservative estimate of offshore NO_2 concentrations, where Shell's operations will be located because the onshore monitors are influenced by local sources. See responses to comments in Category U.

The modeled to monitored pairing approach is also appropriate as there may be changes in NO_2 values throughout the season or time of day. Take, for example, space heating using propane or diesel, which will occur more during the colder months than in the 5 month season of July through November when operations are authorized under the permits. Combustion of propane or diesel for space heating may cause higher monitored NO_2 values in onshore locations (and thus higher background values reflected in the background monitoring data incorporated into Shell's analysis), and this may occur during the 7 month period Shell is not authorized to operate under the permit. Conversely, there may be more activity of other types during the summer months associated with NO_2 emissions. If this is the case, this should be reflected in the background monitoring data incorporated into the modeling analysis. These simple examples help illustrate why, consistent with EPA guidance on modeling for the 1-hour NO_2 NAAQS, using a seasonal monitored value is appropriate for this NAAQS standard. A similar argument will hold for hourly readings during the day. At any one time, a monitor may be impacted by a single source. For that impact to occur and be captured by the monitor the wind has to move or transport the emissions from the source to the monitor. At this point in time the monitor may read a high value, but another location in the vicinity may be experiencing no impacts. By using an average 98th percentile by hour of the day, Region 10 is attempting to account for systematic variations in activities and transport that may be occurring and that would lead to a higher or lower monitoring concentration in any one hour. Region 10 is also attempting to use an appropriate background monitoring value for the entire offshore modeled area. The averaging approach by hour and season used by Shell provides a more realistic but still conservative background value to use for such a large area.

It is also important to consider the form of the standard, which is based on probability. The modeling/monitoring pairing approach used by Shell uses a background concentration for all receptors, again, that is based on a two-year average of the annual 98th percentile value by hour and season. In reality, the actual NO_2 monitoring data indicates there are many hours with zero monitored concentrations. So the pairing approach Shell has used is already increasing the probability of a high modeled value corresponding to a relatively high background value, when in reality the actual monitoring values show many hours of zeros. When this pairing approach is coupled with other assumptions, such as the Kulluk remaining at a single drill location for 3 years, which also increases the probability of high modeled results at a receptor, the end result is a conservative analysis. Even with these conservative assumptions, the analysis has demonstrated that the NAAQS is protected.

Finally, there is no requirement that even a PSD modeling analysis for compliance with the NAAQS be based on "the true maximum impacts that may occur," and using the overall highest 1-hour monitored 1-hour NO_2 concentration as a background value would be overly conservative in this case. Region 10 strongly disagrees with the commenter that compounding adjustments have occurred which will understate the potential maximum impacts. Region 10 believes instead that it is more likely that compounding assumptions actually increase the probability that the analysis Shell submitted would overstate actual impacts at any single receptor. These assumptions include such things as a single well location for three years, having the Associated Fleet always aligned with the prevailing wind directions, not averaging across three years of meteorological data, and using onshore monitoring data to represent overwater locations while using a diurnal pattern of background monitoring values for all hours when monitoring shows many hours of lower concentrations. All of these assumptions compound to form an analysis weighted towards conservatism. See also responses to comments V.1.c, V.2.b, and U.2.

Comment V.2.c: Some commenters support Region 10's decision not to allow a $PM_{2.5}$ modeling analysis that pairs modeled data with monitored data (in time) to determine compliance with the NAAQS, and contend that EPA has in the past said, that pairing data does not ensure protection of the air quality standards, citing to a letter from EPA Region 8. The commenters assert that this approach is needed to ensure that a violation will not occur in the future, not simply to determine that a violation occurred over the period of time modeled. The commenters state that even in recently allowing limited, case-by-case situations where paired data can be modeled to demonstrate compliance with the 1-hour NO_2 NAAQS, EPA is admitting that this type of analysis results in "a less conservative" estimate of impacts, citing to EPA's March 1, 2011 NO_2 Modeling memo. Although these commenters support Region 10's decision not to allow pairing of NO_2 data as Shell originally proposed (*i.e.*, hour-by-hour pairing of modeled concentrations with background concentrations), the commenters do not agree that the diurnal pairing of the 2-year average of the 98^{th} percentile NO_2 concentrations by hour (based on the number of samples) between July 1 and November 30 with corresponding modeled concentrations for that hour is protective enough of the NAAQS. The commenters state that a more protective approach would be to use the 98^{th} percentile of the annual distribution of daily maximum 1-hour average values averaged across the 2-year meteorological data period used in the dispersion modeling and that a more conservative approach is warranted in this case given the fact that the modeling is not based on source specific data and Shell may be under-predicting impacts. The commenters conclude that the use of diuernal pairing results in a less conservative analysis and, given that modeling is based on generic source parameters, this approach does not seem warranted.

Response: The pairing approach used in the 24-hour $PM_{2.5}$ modeling analysis uses the maximum modeled 24-hour $PM_{2.5}$ concentrations averaged over modeled drilling seasons 2009 and 2010, and this value is paired with a representative 98^{th} percentile monitored background concentration for evaluation against the NAAQS. This approach follows EPA guidance and is conservative.

Concerning pairing for the 1-hour NO_2 standard, Region 10 acknowledges the approach taken is potentially "a less conservative" approach than using the 98^{th} percentile annual distribution. The Region believes the approach taken, however, is still protective of the NAAQS and is consistent with EPA guidance. The commenters also fail to address the difference between the two standards, mainly the averaging period of 1-hour versus 24-

hours, and offer no explanation why the pairing approach used for the 1-hour NO_2 standard is not valid and conservative. In addition, it is appropriate to account for diurnal (daily) and seasonal patterns in pairing modeled concentrations with monitored background concentrations. Pairing the 98th percentile of the annual background with the 98th percentile modeled contribution, irrespective of these diurnal or seasonal patterns, may impose additional conservatism that is not warranted. The seasonal pattern is especially relevant in this case because the permits limit operations to a defined period (or season.) Please also see response to comments V.3.a and V.3.b.

V.3 SUBCATEGORY – NO_2/NO_X RATIO

Comment V.3.a: Noting that that the Plume Volume Molar Ratio Method (PVMRM) algorithm used in the ambient analysis to determine the atmospheric conversion of NO_X to NO_2 requires estimates of in-stack ratios of NO_2/NO_X, some commenters assert that these in-stack ratios appear to be important parameters in the modeling. The commenters go on to state that Region 10 must therefore ensure the ratios used are protective of the NAAQS since small changes to the ratios used could have a significant impact on modeled concentrations. The commenters contend that this is especially important in this case given the fact that Shell is requesting approval for the least-conservative options for modeling 1-hour NO_2 impacts (*i.e.*, using the non-regulatory-default PRVRM option – a Tier 3 application under Section 5.2.4, App W that requires Regional approval – and pairing NO_2 data in time.

Response: While EPA has placed greater emphasis on the in-stack NO_2/NO_X ratios required for the PVMRM and OLM Tier 3 options in relation to the 1-hour NO_2 NAAQS as compared to the annual NO_2 NAAQS, due to both the increased stringency and 1-hour daily maximum form of the new standard, the relative importance of this parameter will vary from one application to another. Region 10 cautions against overstating the importance of this input parameter. The relative importance of the in-stack ratios will depend on several factors, including source characteristics, meteorological conditions and background ozone concentrations, but the commenters have provided no support for their broad statement that "small changes to the ratios used could have a significant impact on modeled concentrations." In the extreme case, in terms of the relative importance of the in-stack ratio, with significant ozone-limiting conditions, stable worst-case meteorological conditions and very close ambient air boundary, a small change in the in-stack ratio would only result in a correspondingly small change in the modeled concentrations.

The commenters are correct that Region 10 required Shell to do several iterations of modeling with varying in-stack ratios based on engine testing (*See* 4/29/11 Shell modeling submittal Alternate_NO_2_Modeling_Disco_04_29_2011.pdf). This additional analysis did not indicate significant changes in the modeled 1-hour NO_2 concentrations. Region 10 believes Shell has demonstrated the ratios used are protective of the NAAQS.

See also response to comment V.3.b.

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,