UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Region 4
Atlanta, Georgia

Preliminary Determination & Statement of Basis

Outer Continental Shelf Air Permit Modification OCS-EPA-R4012-M1
For

Statoil Gulf Services, LLC
DeSoto Canyon Lease Blocks

July 9, 2014

Table of Contents

Abbreviations and Acronyms

AP-42	AP-42 Compilation of Air Pollutant Emissions Factors
AQRV	Air Quality Related Values
BACT	Best Available Control Technology
BOEM	Bureau of Ocean Energy Management
Breton NWR	Breton National Wildlife Refuge
BSEE	Bureau of Safety and Environmental Enforcement
Developer	Maersk *Developer*, Drilling Vessel, or the Rig
CAA	Clean Air Act
CCV	Closed Crankshaft Ventilation System
CEMS	Continuous Emissions Monitoring System
CDPF	Catalytic Diesel Particulate Filter
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
DOI	United States Department of the Interior
Discoverer Americas	Transocean *Discoverer Americas* Drillship or the Ship
DPF	Diesel Particulate Filter
EGOM	Eastern Gulf of Mexico
EPA	United States Environmental Protection Agency
ESA	Endangered Species Act
FLAG	FLM Air Quality Related Workgroup
FLM	Federal Land Manager
FTF	Flow through Filter
FWS	United States Fish and Wildlife Service
g/kW-hr	Grams per Kilowatt Hour
GHG	Greenhouse Gas
HAP	Hazardous Air Pollutants
HIP	High Injection Pressure
hp	Horsepower
IMO	International Maritime Organization
km	Kilometer
kPa	Kilopascals
kW	Kilowatt
kW-hr	Kilowatt Hour
LND	Low NO_X Engine Design
m^3	Cubic Meters
MMBtu/hr	Million British Thermal Units per Hour
MSA	Magnuson-Stevens Fishery Conservation and Management Act
NAAQS	National Ambient Air Quality Standards
NEI	National Emissions Inventory
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	Nitrogen Dioxide
NOAA	National Oceanic and Atmospheric Administration
NO_X	Oxides of Nitrogen

NMHC	Non Methane Hydrocarbons
NSPS	New Source Performance Standards
NSR	New Source Review
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
OCV	Open Crankshaft Ventilation System
OSV	Offshore Support Vessel
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter (aerodynamic diameter less than or equal to 2.5 microns)
PM_{10}	Particulate Matter (aerodynamic diameter less than or equal to 10 microns)
ppm	Parts per Million
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
RICE	Reciprocating Internal Combustion Engine
SAM	Sulfuric Acid Mist
SCR	Selective Catalytic Reduction
Statoil	Statoil Gulf Services, LLC or the Applicant
SIL	Significant Impact Level
SMC	Significant Monitoring Concentration
SO_2	Sulfur Dioxide
Support Vessels	Crew Boats and Offshore Support Vessels
THC	Total Hydrocarbon
TPY or tpy	Tons Per Year
TRS	Total Reduced Sulfur
TVP	True Vapor Pressure
ug/m^3	Micrograms per Cubic Meter
U.S.C.	United States Code
VISTAS	Visibility Improvement State and Tribal Association of the Southeast
VOC	Volatile Organic Compounds

1.0 Introduction

On October 28, 2013, the U.S. Environmental Protection Agency (EPA) Region 4 issued an Outer Continental Shelf (OCS) permit (Permit No. OCS-EPA-R4012) to Statoil Gulf Services, LLC (The Applicant or Statoil) in accordance with the provisions of section 328 of the Clean Air Act (CAA), 42 U.S.C. § 7627, and the implementing Outer Continental Shelf Air Regulations at title 40 Code of Federal Regulations (CFR) part 55. The existing permit, which regulates air emissions from the mobilization and operation of deepwater drilling vessels and associated support fleets at multiple lease blocks on the OCS in the eastern Gulf of Mexico, became effective on November 27, 2013.

As stated in the existing permit, Statoil plans to drill using one of two operating scenarios and, dependent on the scenario, will use one of two dynamically positioned deepwater drilling vessels. The Maersk *Developer* drilling vessel, also referred to as Operating Scenario 1, or the Transocean *Discoverer Americas* drillship, also referred to as Operating Scenario 2, along with associated support fleets will be used to conduct the permitted exploratory activities. Drilling operations will last for approximately 180 days per year at multiple locations within Statoil's DeSoto Canyon lease blocks and are expected to occur for approximately five to ten years. The permitted project is for exploratory drilling only. If resource discoveries are made during exploration activities, subsequent facilities, including any necessary production platforms, would be permitted separately.

On April 1, 2014, the EPA received an application from Statoil, dated March 27, 2014, requesting modification of the existing OCS permit to include Best Available Control Technology (BACT) limits for volatile organic compounds (VOC), particulate matter with an aerodynamic diameter less than or equal to 2.5 microns ($PM_{2.5}$), and particulate matter with an aerodynamic diameter less than or equal to 10 microns (PM_{10}) and revised BACT limits for oxides of nitrogen (NO_X) for engines on the *Developer* based on recent source test data for these pollutants that was not available at the time of permitting. Statoil has also requested that the modification decrease the total fuel consumption limit for the *Developer* and change the possible drilling locations for the *Developer* to include additional lease blocks in the same general area. Statoil is not requesting any change in the underlying project plans, which are summarized below. However, the applicant has provided revised air quality modeling which contains changes to operating parameters for the main generating engines and support vessel engines. Statoil believes that the revised modeling is based on more accurate data and is a better representation of the impact of the actual drilling operations. The updated air quality modeling is discussed in Section 7.0 of this document.

Following careful consideration and analysis of the data provided by Statoil, the EPA is proposing to modify the permit to include BACT limits for VOC, $PM_{2.5}$, and PM_{10} and revised BACT limits for NO_X for engines on the *Developer*, decrease the total fuel consumption limit for the *Developer*, and change the possible drilling locations for the *Developer* to include additional lease blocks in the same general area.

This modification does not constitute a change in the source nor a change in the proposed drilling operations. While Statoil has made preparations to drill, including source testing, Statoil has not yet begun drilling operations on the lease blocks covered by the permit. This action is a proposed modification to permitted emissions limits to reflect data that is more representative of actual drilling operations, and to allow the operations to be conducted in additional lease blocks subject to specific criteria as defined in Section 2.2 below. Permit conditions unrelated to the *Developer's* emissions of NO_X, VOC, $PM_{2.5}$, and PM_{10} and operating location have not been modified in this draft permit except where necessary for clarification or to correct typographic errors.

EPA Region 4 is the agency responsible for implementing and enforcing CAA requirements for OCS sources in the Gulf of Mexico east of 87°30’ (87.5°).[1] The EPA has completed a review of Statoil’s application to modify the permit, in addition to all supplemental materials provided, and is proposing to issue Permit Number OCS-EPA-R4012-M1 to Statoil for a multi-year exploratory drilling program subject to the terms and conditions included in this revised permit. The draft modifications to the permit incorporate applicable requirements from the federal Prevention of Significant Deterioration (PSD) and title V operating permit programs. The permit continues to include applicable New Source Performance Standards (NSPS), and National Emission Standards for Hazardous Air Pollutants (NESHAP) as required by the OCS air quality regulations in 40 CFR part 55.

This document serves as a fact sheet, preliminary determination, and statement of basis for the draft permit modification and addresses changes made to the original preliminary determination/statement of basis for this project as a result of the permit revisions. It provides an overview of the project, a summary of applicable requirements, the legal and factual basis for modified draft permit conditions, and the EPA’s analysis of key aspects of the modification application and draft permit conditions such as the BACT analysis and Class II/Class I area impact analysis. Further description of the project and the EPA’s analysis of key aspects of the existing permit and application can be found in the original permit’s application materials submitted to the EPA by Statoil dated September 5, 2012, December 7, 2012, January 28, 2013, and June 27, 2013, and in the original statement of basis for the existing permit (Permit No. OCS-EPA-R4012), which are available in the administrative record for this project, as discussed in Section 9 of this document.

2.0 Applicant Information

2.1 Applicant Name and Address

Statoil Gulf Services, LLC
2103 CityWest Boulevard, Suite 800
Houston, Texas 77042

2.2 Facility Location

Statoil proposes to conduct exploratory drilling at multiple sites within its DeSoto Canyon lease blocks designated Lease Sale areas 213 and 222. These lease blocks (numbers 143, 187, 188, 230, 231, 625, 669, 670, 671, 715, 716, 759, 760, and 804) are located in OCS waters of the Gulf of Mexico east of longitude 87.5°, approximately 160 miles southeast of the mouth of the Mississippi River and 200 miles southwest of Panama City, Florida as illustrated below in Figure 2-1. Each lease block is approximately five kilometers by five kilometers.

Statoil is requesting that the permit be modified to include additional lease blocks in the same eastern Gulf of Mexico area, which meet the following location criteria:

- Located east of 87°30’ west longitude in the eastern Gulf of Mexico;

[1] *See* CAA section 328. The Department of the Interior has jurisdiction for CAA implementation west of 87°30’.

- Farther from the closest lease block modeled as part of the project defined in Permit No. OCS-EPA-R4012 and this draft permit relative to the closest shoreline, the Breton Wilderness Class I area, or any Class I or Class II area;
- West of the Military Mission Line (86°41' west longitude);
- Outside of the current Congressional moratoria area as specified by the Gulf of Mexico Energy Security Act of 2006; and
- Outside 75 nautical miles of the state seaward boundary of Florida.

After a review of the information provided by Statoil, the EPA concurs that inclusion of this flexibility while operating under Operating Scenario 1 with the *Developer* would be protective of air quality if any additional lease block location that meets the criteria listed above and is subject to the same conditions used to judge the worst-case location in the application. The worst-case location with respect to modeled air pollutant emissions is considered to be the northwest corner of lease block 143, which is closest to shore and to the Breton Wilderness Class I area. Proposed language has been added to the permit to allow this flexibility. Written notification to the EPA of all drilling locations prior to the commencement of operations remains a condition of the modified permit.

Figure 2-1 Site Location

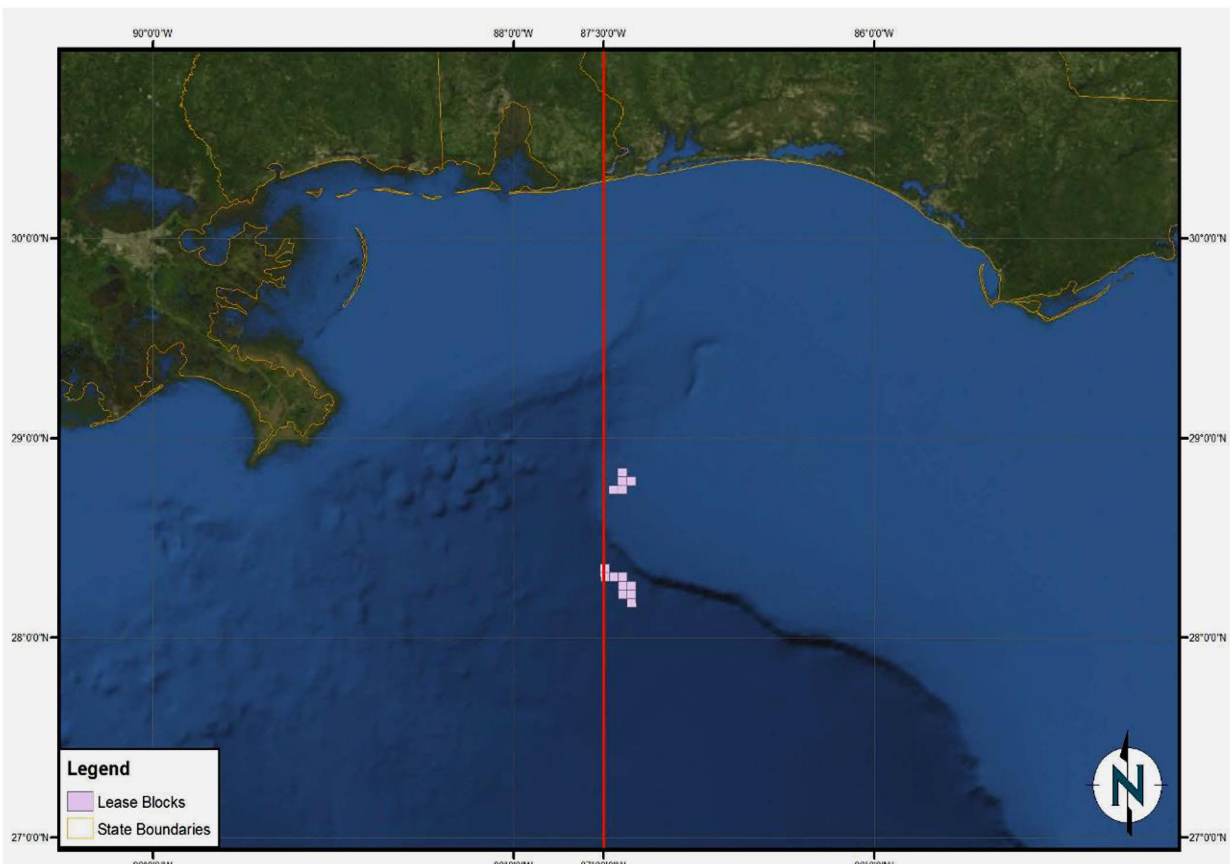

Image reproduced from Outer Continental Shelf Title V Permit Significant Modification and PSD Permit Major Modification Application DeSoto Canyon Drilling Exploration Project for Statoil Gulf Services LLC dated March 2012, prepared by ENVIRON International Corporation Baton Rouge, Louisiana.

3.0 Proposed Project

The proposed modification does not constitute a change in the source nor a change in the proposed drilling operations. Statoil is still proposing to operate either the *Developer* (Operating Scenario 1) or the *Discoverer Americas* (Operating Scenario 2) deepwater drilling vessels and their associated support fleets to perform exploratory drilling activities for approximately 180 days per year at multiple locations within their currently held lease blocks in the DeSoto Canyon area of the Gulf of Mexico or, if using the *Developer*, in any future lease block held that meets the criteria listed in Section 2.2 above. It is expected that drilling operations will occur for approximately five to ten years. Emissions are primarily released from the combustion of diesel fuel in the drilling vessels' main engines and in smaller engines that supply power for operating drilling equipment and support vessels. Emissions may also be released from other equipment such as fuel and mud storage tanks and from activities such as cementing the wells, pumping heavy lubricating mud, painting, and welding.

Air pollutant emissions generated from the project include the criteria pollutants nitrogen dioxide (NO_2), carbon monoxide (CO), particulate matter (PM), $PM_{2.5}$, PM_{10}, and sulfur dioxide (SO_2), as well as other regulated air pollutants including VOC, NO_X, and greenhouse gases (GHGs).[2] VOC and NO_X are the measured precursors for the criteria pollutant ozone, and NO_X and SO_2 are measured precursors for $PM_{2.5}$.

In the existing OCS permit, emissions from the *Developer* are subject to PSD and title V requirements for NO_X only (as a measured pollutant for criteria pollutants NO_2 and ozone and as a precursor to $PM_{2.5}$) based on emissions estimates and the applicable permitting thresholds. However, Statoil conducted source testing in October 2013 for NO_X, CO, PM, and VOC emissions indicating that emissions of VOC (as the measured pollutant for criteria pollutant ozone) and criteria pollutants PM_{10} and $PM_{2.5}$ also have the potential to meet or exceed the respective significant emission rates for the *Developer*. The source testing also indicated that emissions of NO_X from the main generating engines were higher than those estimated at the time of the original permit application. Therefore, Statoil has requested a permit modification to include BACT limits for PM_{10}, $PM_{2.5}$, and VOC and revised BACT limits for NO_X for the main engines on the *Developer*. Activities conducted under this modified operating scenario continue to be considered an area source of hazardous air pollutants pursuant to 40 CFR 63 subpart ZZZZ.

Included in its application to revise the BACT limits for NO_X and to include BACT limits for VOC, PM_{10}, and $PM_{2.5}$ for the *Developer*, Statoil performed a revised BACT analysis, a revised air quality analysis, and updated its Potential to Emit (PTE) for these pollutants with respect to Operating Scenario 1, as discussed below.

3.1 Operating Scenario 1 (Maersk *Developer*)

The *Developer* (Figure 3-1) is a self-powered, dynamically positioned semi-submersible drilling vessel with pontoon structures below the water surface and a platform above the surface. Positioning is achieved using a computer controlled system and its propellers and thrusters. Therefore, the *Developer* will not require the use of towing or anchoring vessels as part of its support fleet.

The rig is equipped with eight main generator engines to provide propulsion and electrical power, two cementing unit engines, an emergency generator, four life boats, a fast rescue boat (also known as a man

[2] Section 4 of the modified permit clarifies which Global Warming Potential factors are applicable to the project.

overboard boat), and storage vessels for fuel and waste oil. Electric powered well logging wireline units, vertical seismic profile compressors, forklifts, and cranes are used on the rig. However, since the electric units do not have combustion engines, they are not addressed as a separate source of air emissions. Maintenance activities, such as welding and painting, also emit small amounts of air pollutants.

Cement and barite used in casing and drilling activities is mixed in an enclosed system on the *Developer* and was not thought to be a source of potential emissions in the original permit application. However, the modification application indicates that particulate emissions from cement and barite handling may contribute to particulate emissions on the vessel. Therefore, conditions related to this activity have been added to the modified draft permit.

Support vessels operating within 25 miles of the drill rig will include crew boats and offshore support vessels (OSVs) that will bring crew, supplies, and materials to the rig as needed during exploratory drilling activities. In addition, crew and time-sensitive supplies may be transported to and from the drillship via helicopters. Statoil will rely on a fleet of support vessels in two categories: OSVs and crew boats. There is no proposed change in the use and operation of the support vessels from the existing OCS permit. Therefore, permit conditions related to the support vessels have not been modified in the draft permit except where necessary for clarification or to correct typographic errors.

Engine details and emissions information are provided in Section 5.0 of this document.

Figure 3-1 Maersk *Developer* Drill Rig

Image reproduced from Outer Continental Shelf Title V Permit Significant Modification and PSD Permit Major Modification Application DeSoto Canyon Drilling Exploration Project for Statoil Gulf Services LLC dated March 2012, prepared by ENVIRON International Corporation Baton Rouge, Louisiana.

3.2 Operating Scenario 2 (Transocean *Discoverer Americas*)

Statoil has not applied for any changes to Operating Scenario 2 using the Transocean *Discoverer Americas* and no permit requirements involving this drillship have been modified except where necessary for clarification or to correct typographic errors. Therefore, details regarding this drill ship are not included in this preliminary determination and statement of basis.

4.0 Legal Authority and Regulatory Applicability

4.1 EPA Jurisdiction

The 1990 CAA Amendments transferred authority for implementation of the CAA for sources subject to the Outer Continental Shelf Lands Act (OCSLA) from the Department of the Interior (DOI) to the EPA for all areas of the OCS with the exception of the Gulf of Mexico west of 87.5° longitude. Subsequently, the Consolidated Appropriations Act, 2012 (P.L. 112-74), transferred authority from EPA to DOI for areas offshore the North Slope of Alaska.

4.2 OCS Air Regulations

Section 328(a)(1) of the CAA requires the EPA to establish requirements to control air pollution from OCS sources under EPA's jurisdiction, in order to attain and maintain federal and state ambient air quality standards and to comply with the provisions of part C (PSD) of title I of the CAA. The OCS Air Regulations at 40 CFR part 55 implement section 328 of the CAA and establish the air pollution control requirements for OCS sources and the procedures for implementation and enforcement of these requirements. The regulations define "OCS source" by incorporating and interpreting the statutory definition of OCS source:

OCS source means any equipment, activity, or facility which:

(1) Emits or has the potential to emit any air pollutant;
(2) Is regulated or authorized under the OCSLA (*see* 43 U.S.C. §1331 et seq.); and
(3) Is located on the OCS or in or on waters above the OCS.

This definition shall include vessels only when they are:

(1) Permanently or temporarily attached to the seabed and erected thereon and used for the purpose of exploring, developing or producing resources there from, within the meaning of section 4(a)(I) of the OCSLA (*see* 43 U.S.C. §1331 et seq.); or
(2) Physically attached to an OCS facility, in which case only the stationary source aspects of the vessels will be regulated [*see* 40 CFR § 55.2; *see also* CAA § 328(a)(4)(C) and 42 U.S.C. § 7627].

Section 328 and part 55 distinguish between OCS sources located within 25 miles of a state's seaward boundary and those located beyond 25 miles of a state's seaward boundary [*see* CAA § 328(a)(1); 40 CFR §§ 55.3(b) and (c)]. In this case, Statoil's exploratory drilling operations will be conducted exclusively beyond 25 miles of any state's seaward boundary.

Sources located beyond 25 miles of a state's seaward boundaries are subject to the NSPS in 40 CFR part 60; the PSD pre-construction program in 40 CFR § 52.21, if the OCS source is also a major stationary source or a major modification to a major stationary source; standards promulgated under section 112 of the CAA, if rationally related to the attainment and maintenance of federal and state ambient air quality standards or the requirements of part C of title I of the CAA; and the title V operating permit program in 40 CFR part 71. *See* 40 CFR §§ 55.13(a), (c), (d)(2), (e), and (f)(2), respectively. The applicability of these requirements to Statoil’s exploratory drilling program is discussed below.

The OCS regulations also contain provisions related to monitoring, reporting, inspections, compliance, and enforcement. *See* 40 CFR §§ 55.8 and 55.9. Sections 55.8(a) and (b) provide that all monitoring, reporting, inspection, and compliance requirements of the CAA apply to OCS sources. These provisions, along with the provisions of the applicable substantive programs listed above, provide authority for the monitoring, recordkeeping, reporting and other compliance assurance measures included in Statoil’s permit.

4.3 Prevention of Significant Deterioration (PSD)

The PSD program, as set forth in 40 CFR § 52.21, is incorporated by reference into the OCS Air Regulations at 40 CFR § 55.13(d)(2), and is applicable to major OCS sources such as this project. The PSD program requires an assessment of air quality impacts from the proposed project and the utilization of BACT as determined on a case-by-case basis taking into account energy, environmental, and economic impacts, as well as other costs.

Under the PSD regulations, a stationary source is “major” if, among other things, it emits or has the potential to emit (PTE) 100 ton per year (TPY) or more of a “regulated NSR pollutant” as defined in 40 CFR § 52.21(b)(50); is “subject to regulation” as defined in 40 CFR § 52.21(b)(49); and is one of a named list of source categories. Any stationary source is also considered a major stationary source if it emits or has a PTE of 250 TPY or more of a regulated NSR pollutant. *See* 40 CFR § 52.21(b)(l).

“Potential to emit” is defined as the maximum capacity of a source to emit a pollutant under its physical and operational design. *See* 40 CFR § 52.21(b)(4). In the case of “potential emissions” from OCS sources, 40 CFR part 55 defines the term similarly and provides that:

> *Pursuant to section 328 of the Act, emissions from vessels servicing or associated with an OCS source shall be considered direct emissions from such a source while at the source, and while en route to or from the source when within 25 miles of the source, and shall be included in the “potential to emit” for an OCS source. This definition does not alter or affect the use of this term for any other purposes under 40 CFR §§ 55.13 or 55.14 of this part, except that vessel emissions must be included in the “potential to emit” as used in 40 CFR §§ 55.13 or 55.14 of this part. (40 CFR § 55.2)*

Thus, emissions from vessels servicing or associated with an OCS source that are within 25 miles of the OCS source are considered in determining the PTE or “potential emissions” of the OCS source for purposes of applying the PSD regulations. Emissions from such associated vessels are therefore counted in determining whether the OCS source is required to obtain a PSD permit, as well as in determining the pollutants for which BACT is required.

The drilling vessel and support fleet vessels may contain emission sources that otherwise meet the definition of “nonroad engine” as defined in section 216(10) of the CAA. However, based on the specific requirements of CAA section 328, emissions from these otherwise nonroad engines on subject vessels are considered as “potential emissions” from the OCS source. Similarly, all engines that are part of the OCS source are subject to the requirements of 40 CFR part 55, applicable to the OCS source, including control technology requirements.

Table 4-1 lists the PTE for each regulated NSR pollutant from the *Developer* for which Statoil is seeking a new or revised BACT limit based on the October 2013 source testing, as well as the significant emission rate for these pollutants. The permit application materials and Section 5.0 of this document contain information regarding the emissions factors used to determine PTE for these pollutants under Operating Scenario 1. Emissions from support vessels servicing each drilling vessel were considered direct emissions while within 25 miles of the drilling vessel and are included in the PTE.

The requirements of the PSD program apply to this OCS source if the project PTE is at least 250 TPY for any regulated pollutant. Statoil’s exploration drilling program is a major PSD source because emissions of NO_X exceed the major source applicability threshold of 250 TPY. Therefore, Statoil is required to apply BACT and address air quality impact requirements for NO_X, both as the measured pollutant for NO_2 and ozone and as a precursor to ozone and $PM_{2.5}$. Based on results of the October 2013 source testing, the PTE for VOC (as a measured pollutant for criteria pollutants ozone, PM_{10}, and $PM_{2.5}$) has changed and is above the applicable significant emissions rates. A PSD review and BACT analysis are therefore required for these pollutants. Section 6.0 of this document contains a discussion of the BACT analysis.

Table 4-1 Potential to Emit for Regulated NSR Pollutants Based on Source Testing

Pollutant	Scenario 1 (*Developer*) PTE (TPY)	Significant Emission Rate (TPY)	PSD Review Required
NO_X[1]	554.05	40	Yes
VOC[2]	75.65	40	Yes
PM_{10}	17.47	15	Yes
$PM_{2.5}$	16.03	10	Yes

[1] NO_X is a measured pollutant for the criteria pollutants ozone and NO_2 and a precursor for ozone and $PM_{2.5}$.
[2] VOC is a measured pollutant for the criteria pollutant ozone.

4.4 Title V

The requirements of the title V operating permit program, as set forth in 40 CFR part 71, apply to major OCS sources located beyond 25 miles of any state's seaward boundaries. *See* 40 CFR § 55.13(f)(2). Because the PTE for this project is greater than 100 TPY for NO_X, it is considered a major source under title V and part 71. Title V permit requirements were included in the OCS permit issued for this source on October 28, 2013. The proposed permit changes constitute a significant modification to the title V permit because they do not meet the criteria set out for a minor modification under 40 CFR 71.7(e)(1). More specifically, the revisions require a case-by-case determination of emissions limits. While the permit revisions constitute a “modification” pursuant to part 71, they do not constitute a modification to the emissions units or planned operation of the facility (i.e., this is not a physical change or a change in the method of operation, as defined under PSD). The permit continues to include all the permit terms necessary to meet the requirements of the applicable title V operating permits program. For example, the draft permit includes requirements for submittal of annual compliance certifications and annual fee payments based on actual emissions, as well as monitoring, recordkeeping, and reporting requirements.

Updated part 71 forms for Operating Scenario 1 are included as Appendix A of Statoil's March 2014 modification application.

4.5 New Source Performance Standards (NSPS)

An OCS source must comply with any NSPS applicable to their source category. *See* 40 CFR § 55.13(c). In addition, per 40 CFR § 52.21(j)(1), the PSD regulations require that each major stationary source or major modification meet applicable NSPS. A specific NSPS subpart applies to a source based on source category, equipment capacity, and the date when the equipment commenced construction or modification. Engine specifications for diesel engines on the *Developer* are summarized in Table 4-2. NSPS requirements have not changed since the existing permit was issued on October 28, 2013 and are not affected by the proposed permit changes. Therefore, no modifications regarding NSPS requirements have been made to the permit.

Certification documentation for the main generator engines, the emergency generator engine, and the cementing unit engines are provided in Appendix B of the modification application.

Table 4-2 *Developer* Engine Specifications

Emissions Unit ID	Engine Description	Manufacturer and Model	Displacement (L/cylinder)	Rating[a] (kW)	Rating[a] (hp)	Manufacture Date
GEN-1	Main Generator Engine 1	Wärtsilä 16V26A	17.0	4840	6651	8/2006
GEN-2	Main Generator Engine 2	Wärtsilä 16V26A	17.0	4840	6651	8/2006
GEN-3	Main Generator Engine 3	Wärtsilä 16V26A	17.0	4840	6651	8/2006
GEN-4	Main Generator Engine 4	Wärtsilä 16V26A	17.0	4840	6651	8/2006
GEN-5	Main Generator Engine 5	Wärtsilä 16V26A	17.0	4840	6651	8/2006
GEN-6	Main Generator Engine 6	Wärtsilä 16V26A	17.0	4840	6651	8/2006
GEN-7	Main Generator Engine 7	Wärtsilä 16V26A	17.0	4840	6651	8/2006
GEN-8	Main Generator Engine 8	Wärtsilä 16V26A	17.0	4840	6651	8/2006
EGEN	Emergency Generator Engine	Caterpillar 3516B	4.9	1902	2551	11/2006
CMU-1	Cement Unit Engine 1	Caterpillar C15	2.4	373	500	10/2006
CMU-2	Cement Unit Engine 2	Caterpillar C15	2.4	373	500	9/2006
LB-1	Lifeboat 1 Engine	BUKH	---	22	29	8/2007
LB-2	Lifeboat 2 Engine	BUKH	---	22	29	8/2007
LB-3	Lifeboat 3	BUKH	---	22	29	8/2007

Emissions Unit ID	Engine Description	Manufacturer and Model	Displacement (L/cylinder)	Rating[a] (kW)	Rating[a] (hp)	Manufacture Date
	Engine					
LB-4	Lifeboat 4 Engine	BUKH	---	22	29	8/2007
MOB-1	Fast Rescue Boat Engine	Steyr Motors	---	122	163	3/2007

[a] Permit conditions may limit operation to less than rated capacity.

4.6 National Emission Standards for Hazardous Air Pollutants (NESHAP)

Applicable NESHAP promulgated under section 112 of the CAA apply to OCS sources if rationally related to the attainment and maintenance of federal and state ambient air quality standards or the requirements of part C of title I of the CAA. *See* 40 CFR § 55.13(e). NESHAP requirements applicable to the project have not changed since the existing permit was issued on October 28, 2013 and are not affected by the proposed permit changes. Therefore, no modifications regarding NESHAP requirements have been made to the permit.

5.0 Project Emissions

5.1 Potential to Emit

This section describes the calculation basis for NO_X, VOC, SO_2 (as a precursor for $PM_{2.5}$) and particulate emissions generated during exploratory drilling operations from each emission source. The calculations are based on AP-42 factors, EPA publications, analysis of fuel sulfur content, vendor compliance certifications, vendor-supplied emissions factors, and recent source testing. The total projected emissions include estimates based on fuel consumption from the diesel engines. Emissions from other sources on the drilling vessels and support vessels are based on worst case PTE conditions for the individual sources. Updated calculations based on the October 2013 main generator engine emissions testing results are included in Section 3 and Appendix B of Statoil's March 2014 modification application. All documents submitted to the EPA in support of these calculations are included in the administrative record as discussed in Section 9.0 of this document. The table below provides the revised PTE of the project for NO_X, VOC, SO_2, and particulate emissions using Operating Scenario 1, based on the recent source testing results of the eight main diesel engines.

Table 5-1 Potential to Emit Emissions – Operating Scenario 1 (*Developer*)

Emission Source	Total VOC (TPY)	NO_X (TPY)	SO_2 (TPY)	PM (TPY)	PM_{10} (TPY)	$PM_{2.5}$ (TPY)
Wärtsilä Diesel Generator Engines	66.12	416.15	0.36	15.58	12.81	12.43
Emergency Diesel Generator Engine	0.04	0.76	5.47e-04	2.46e-02	2.02e-02	01.96e-2
Lifeboat Engines	1.75e-03	8.58e-03	7.57e-06	6.87e-04	5.64e-04	5.48e-04

Emission Source	Total VOC (TPY)	NO_X (TPY)	SO_2 (TPY)	PM (TPY)	PM_{10} (TPY)	$PM_{2.5}$ (TPY)
Fast Rescue Boat Engines	0.00	0.01	1.06e-05	6.43e-04	5.29e-03	5.13e-04
Cement Unit Engines	0.19	0.89	8.15e-04	0.025	0.020	0.020
Offshore Support Vessels	4.29	108.99	0.07	2.97	2.44	2.37
Crew Boats	1.76	27.24	0.03	0.77	0.63	0.61
Storage Tanks	0.39	--	--	--	--	--
Fugitive Emissions	0.84	--	--	--	--	--
Mud Degassing	0.48	--	--	--	--	--
Painting	1.54	--	--	0.48	0.33	0.12
Welding	--	--	--	0.01	0.01	0.01
Cement/Barite Handling	--	--	--	1.90	1.21	0.46
Total	75.65	554.05	0.45	21.75	17.47	16.03

[1]NO_X is a measured pollutant for the criteria pollutants ozone and NO_2 and a precursor for ozone and $PM_{2.5}$.
[2] VOC is a measured pollutant for the criteria pollutant ozone.
[3] SO_2 is a precursor for the criteria pollutant $PM_{2.5}$.

5.2 Operating Scenario 1 (*Developer*) Emissions Source Analysis

The following is a description of the *Developer's* emission units and how emissions of NO_X, VOC, SO_2, and particulate emissions were calculated for each permitted activity under Operating Scenario 1. Potential emissions of regulated air pollutants are estimated to be less than 2 TPY and HAP emissions are estimated to be less than 1,000 lb/yr from the lifeboat engines, fast rescue boat engines, mud degassing, welding activities, fugitive emissions, cement/barite handling activities, and storage tanks. Therefore, they are considered insignificant activities with respect to title V permit requirements per 40 CFR 71.5(c)(11)(ii).

The current permit contains an annual fuel limitation of 2,654,931 gallons of diesel fuel on a rolling 12-month basis. Based on Statoil's recent study of the *Developer's* operations while drilling, Statoil has indicated that fuel consumption will be less than estimated in their original application. Therefore, EPA has proposed a revised annual fuel limitation of 2,459,150 gallons of diesel fuel on a rolling 12-month basis. This estimate is based on fuel use estimates for a typical 180-day drilling campaign as provided in the modification application materials. If the two drilling vessels, the *Developer* and the *Discoverer Americas*, are used sequentially during any rolling 12-month period, the annual fuel use limitation must be prorated based on daily use. Emissions calculations for each source are included in Section 3 and Appendix B of Statoil's March 2014 modification application.

GEN-1 through GEN-8: Main Diesel Generator Engines
The *Developer's* electrical power is provided by eight identical Wärtsilä 16V26A diesel generator engines (main engines) with a rated power output of approximately 6,651 hp each. Emissions estimates for the main engines are based on an anticipated 180 days of drilling operation per year (4,320 hours annually) and maximum emission factors based on source testing completed in October 2013.

Estimates for the annual emissions rates for NO_2 and particulate matter, representing normal operating conditions, were based on the eight main generator engines operating at 12 varying operational modes for 180 days of drilling activity. Estimates for the maximum short-term (1-hour and 24-hour) emission rates for NO_2, PM_{10}, and $PM_{2.5}$ air quality modeling were based on five main generator engines operating at the highest emission rate measured for each relevant pollutant during the October 2013 emissions testing. SO_2 emissions were estimated based on chemical analysis of the sulfur content of the diesel fuel. Specific emission factors used to estimate the project's emissions are included in Section 3 of Statoil's March 2014 application.

EGEN: Emergency Generator Engine
The emergency generator's diesel engine is powered by a Caterpillar (3516B) 2,551 hp engine that provides emergency power to the drilling vessel and is run periodically to ensure that the engine will operate properly in the event of an emergency. The planned operating time for routine testing and maintenance of 39 hours per year on a rolling 12-month average basis at 100% capacity was used for emission calculations and was included as a limit in the permit to ensure consistency with the assumptions used in the application and impact review. This limit was not revised.

CMU-1 and CMU-2: Cement Unit Diesel Engines
The cementing units are used to produce and pump cement around the well casing during drilling operations to provide stability to the casing. Each unit has a 500 hp Caterpillar C15 diesel engine. Emissions were calculated for these units using an estimated annual schedule of 300 combined hours per year of operation on a rolling 12-month average basis. Operating hours for the cement unit diesel engines are limited to 300-hr per year in the permit to ensure consistency with the assumptions used in the application and impact assessment. This limit was not revised.

LB-1 through LB- 4: Life Boats
The 29 hp engines powering each life boat are operated during maintenance checks, safety checks and in the event of an emergency. Planned operating time of 12 hours per year at maximum capacity was used for the emission calculations for each unit. An operational limit reflecting the planned operation time for routine testing, drills, and maintenance is included in the permit to ensure consistency with the assumptions used in the application and impact assessment and was not revised.

MOB: Fast Rescue Boat
The 163 hp engine in the fast rescue boat is operated during maintenance checks, safety checks and in the event of an emergency. Planned operating time of 12 hours per year at maximum capacity was used for the emission calculations. An operational limit reflecting the planned operation time for routine testing, drills, and maintenance is included in the permit to ensure consistency with the assumptions used in the application and impact assessment and remains unchanged.

WELD: Welding Activities
Maintenance and repair conducted while the vessel is operating under the terms of the OCS permit may require limited welding activities. Welding emissions were calculated based on the estimated number

and type of welding electrodes used per 180-day drilling campaign. Monitoring and recordkeeping conditions have been included as draft permit revisions to ensure consistency with the assumptions and methodology used in the modification application.

PAINT: Painting Activities

Maintenance and repair conducted while the vessel is operating under the terms of the OCS permit may require limited painting activities. Paint may be applied by spraying or rolling and may occur inside or outside the vessel. Statoil based the emissions from painting on the estimated amount of paint and thinner used during a 180 day drilling campaign, assuming 100% sprayer-applied outside painting for the most conservative estimate. Maximum potential VOC and HAPs content was obtained from material safety data sheets for available paints and thinners. Based on information from the South Coast Air Quality Management District, a transfer efficiency of 65% and a total PM overspray fractionation of 70% PM_{10} and 25% $PM_{2.5}$ were used to estimate VOC and particulate matter emissions, respectively. Monitoring and recordkeeping conditions are proposed in the revised permit to ensure consistency with the assumptions and methodology used in the modification application.

CEMENT-BARITE: Cement and Barite Handling Activities

Barite and cement handing occurs in a closed system equipped with dust collection. Vents from receiving components are routed to a common collection header and entrained particulate matter is routed under water via a submerged collection hose. Statoil estimates the control efficiency of the dust collection system to be nearly 100%. With this modification application, barite/cement particulate emissions are being included in the *Developer* emission calculations to account for potential particulate emissions. Particulate matter emissions were estimated based on PM emissions resulting from 1,440 hours of cement/barite transfer activities per year and the use of AP-42 particle size distribution factors to determine PM_{10} and $PM_{2.5}$ fractions. Monitoring and recordkeeping conditions are proposed in the revised permit to ensure consistency with the assumptions and methodology used in the modification application.

MUD: Mud Degassing

Drilling mud circulating from the well to the drilling vessel may contain hydrocarbons, particularly if the drill bit is passing through rock in a hydrocarbon zone. These gases can then volatilize to the atmosphere. Statoil calculated emissions from the drilling mud using an estimate of one day of drilling in hydrocarbon-containing rock per well and an estimated four wells drilled annually. EPA document *Atmospheric Emissions from Offshore Oil and Gas Development and Production* (450/3-77/026), June 1977 was used as the basis for drilling mud emissions calculations. Monitoring and recordkeeping conditions are proposed in the revised permit to ensure consistency with the assumptions and methodology used in the modification application.

FUG: Fugitive Emissions Sources

Fugitive emissions from each drilling scenario were based on the number of fugitive components (*e.g.*, piping, valves, flanges) identified on the drilling vessel's fuel system piping and instrumentation diagrams in conjunction with emissions factors contained in Table 2-4 of the *Protocol for Equipment Leak Emission Estimates* (EPA-453/R-95-017). Monitoring and recordkeeping conditions are proposed in the revised permit to ensure consistency with the assumptions and methodology used in the modification application.

Storage Tanks

VOC emissions are generated from the storage of diesel fuel, aviation fuel for the helicopters, and waste oil. Refueling and unloading emissions associated with the support vessels are also included in the storage unit emissions calculations. Statoil used the EPA TANKS 4.09d computer software program to calculate potential emissions. The default EPA TANKS 4.09d properties for Distillate Fuel Oil No. 2 and Jet Naphtha were used to calculate emissions for the diesel/waste oil storage tanks and for the aviation fuel storage tanks, respectively.

5.3 Support Vessel Analysis

Crew boat calculations are based on 618 operating hours per year resulting in 235,176 gallons of diesel consumed per year when within 25 miles of the drilling vessel. To estimate annual emissions from OSVs, Statoil based the calculations on 2,570 operating hours annually resulting in 621,468 gallons of diesel consumed per year when within 25 miles of the drilling vessel. Changes in the use and operation of the support vessels from the existing OCS permit were not proposed in the modification application. The planned operation times for each support vessel category were used for emission calculations and are included as operational limits in the permit to ensure consistency with the assumptions used in the application and impact review. Conditions included in the revised permit remain unchanged from the existing permit. However, the applicant has proposed changes to several operating parameters used in the revised air quality modeling to better reflect actual emissions and overall drilling operations. The revised air quality modeling is discussed in Section 7.0 of this document.

The OSV (*Peyton Candies*) and crew boat (*Sybil Graham*) were identified as the highest emitting support fleet vessels. Detailed emission factors for these sources are available in Statoil's March 2014 modification application, which is included in the administrative record referenced at the end of this document.

5.4 Compliance Methodology

The revised permit continues to define and allow the following three systems for monitoring of NO_X, VOC, PM_{10}, and $PM_{2.5}$ from the main generator diesel units on the *Developer* (GEN-1 through GEN-8):

- An EPA-approved parametric monitoring method;
- An EPA-approved continuous emissions monitoring system; or
- A stack testing emissions monitoring system, if approved in writing by the EPA prior to stack testing.

A combination of these methods, as necessary for different pollutants or engines, may also be used.

The compliance demonstration method for the emergency generator diesel unit (EGEN), the cementing unit engines (CMU-1 and CMU-2), and the emergency vessels (LB-1 through 4 and MOB) on the *Developer* includes monitoring and maintaining a contemporaneous record of the hours of engine operation using an engine hour meter, or recordkeeping of unit ID, date/time the engine started, date/time the engine shut down, the printed name of the person operating the equipment and the signature of the person operating the equipment. These units must also meet any applicable NSPS and NESHAP monitoring requirements. The recorded hours of operation will be used along with the appropriate emissions factors for each engine to determine the total NO_X, VOC, PM_{10}, and $PM_{2.5}$ emitted. Monitoring and recordkeeping requirements for these engines remain unchanged from the existing permit.

Compliance demonstration for the support vessels also remains unchanged, as specified in the existing permit, and includes:

- Monitoring and maintaining a contemporaneous record of operating and standby time within the 25 mile radius of the drilling vessel;
- Determining and recording sulfur content upon receiving each fuel shipment;
- Maintaining a record of the number of gallons of diesel fuel on the support vessel entering the 25 mile radius; and
- Maintaining a record of the number of gallons of diesel fuel on the support vessel exiting the 25 mile radius.

The permit continues to require Statoil to supply the EPA with all records that are required to be kept as a condition of the permit upon request. In addition, Statoil is required to provide a semi-annual report of its emissions information and calculations in accordance with all relevant permit conditions.

6.0 Best Available Control Technology (BACT) and Recordkeeping Requirements

A new major stationary source subject to PSD requirements is required to apply BACT for each pollutant subject to regulation under the CAA that it would have the potential to emit in amounts equal to or greater than the pollutant's significant emission rate. *See* 40 CFR § 52.21(j). Statoil is seeking a permit modification to include BACT limits for VOC, PM_{10}, and $PM_{2.5}$ and revised BACT limits for NO_X for main engines on the *Developer* based on the recent source testing data for these pollutants that was not available at the time of permitting. The current permit contains BACT limits for NO_X; however, the recent source test data indicates that NO_X emissions will be higher than those anticipated at the time that Statoil applied for the original permit and that VOC, PM_{10}, and $PM_{2.5}$ will be emitted in quantities exceeding significant emissions thresholds under Operating Scenario 1. Therefore, BACT must be determined for each emission unit on the drilling vessel that has the potential to emit NO_X, VOC, PM_{10}, or $PM_{2.5}$ while operating as an OCS source, with the exception of the life boat and fast rescue craft engines.

The life boats and the fast rescue boats are included in the OCS source's PTE and emissions modeling, as required by 40 CFR part 55, and are subject to operating limits, monitoring, recordkeeping and reporting requirements to ensure they will not exceed the potential emissions assumed in the application and impact review. Vessels operating within 25 miles of the OCS source are not subject to BACT requirements unless they are attached to the OCS, and then only the stationary source aspects of the vessel are regulated. *See* 40 CFR § 55.2. These units do not have any stationary source aspects with respect to NO_X, VOC, PM_{10}, or $PM_{2.5}$ emissions, as they are used for man overboard and emergency escape scenarios only.

The main generator engines on the drilling vessel continuously operate at variable loads based on drilling and operational power demand. Consequently, pollutants are not emitted from these engines at a steady state. In addition, engine efficiency and performance typically degrades over time, resulting in increased emissions. These factors are important considerations in the BACT analysis for these engines.

Source testing, conducted in October 2013, in accordance with Condition 6.5 of the existing permit, yielded data that was generally higher than the respective BACT limits for NO_X, in the existing permit and established that emissions would exceed the PSD significant emissions thresholds for PM_{10}, $PM_{2.5}$, and VOC. The test was performed for three runs each at high, medium and low loads and included emissions data results for NO_X, total hydrocarbons (THC), CO, and PM at engine loads of 30%, 45%, and 60%. Due to testing time constraints, direct PM measurements were not made at the 45% engine load, but were interpolated from the high and low load runs.

The original emission estimates and BACT limits were based on AP-42 emission factors and vendor data due to the lack of actual emissions data for the aforementioned pollutants on this drilling vessel or like drilling vessels. The AP-42 factors that were relied upon by the applicant (AP-42, Section 3.4 Large Stationary Diesel Engines) are from a very limited sampling (i.e., the testing of one engine only) and may not be the most favorable information in terms of accuracy or reliability. Furthermore, the AP-42 factors and vendor data are more representative of land-based rather than marine-based applications and specifically do not account for the frequent variable load scenarios and operating characteristics associated with drilling operations. In addition, the vendor data is based on laboratory test cycles, which often does not reflect in-use operating conditions. Nonetheless, these factors were the best available at the time the existing permit was issued.

Following careful consideration and analyses of the data provided by Statoil, the EPA is proposing to revise the BACT limits for NO_X and establish BACT limits for PM_{10}, $PM_{2.5}$, and VOC for the main generating engines on the *Developer* as specified in the draft permit conditions.

A single BACT limit was proposed by Statoil for each pollutant that generally correlated to the highest 3-run average test result from a single engine, irrespective of the operating load. Upon analysis of the data, however, the EPA determined that separate emission limits for low load and high load operations are more appropriate for the particulate matter and VOC emission limits. Emission rates for these pollutants are significantly higher at low loads. This is expected due to the combustion characteristics of the diesel engines. In addition, in establishing BACT limits, the EPA considered correlation of the data across the test runs, as significant deviations may be an indicator of poor test results or operations outside of optimum performance. Therefore, the EPA has proposed high and low load limits that are more reflective of the variable load operations of these engines when operating under the terms of the permit.

6.1 BACT Analysis Procedure

A top-down BACT analysis was conducted by the applicant and a BACT determination made for each emissions unit of the *Developer* that has the potential to emit NO_X, PM_{10}, $PM_{2.5}$, and/or VOC.

BACT is defined in the applicable permitting regulations at 40 CFR § 52.21(b)(12), in part, as:

> *an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event, shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the*

Administrator determines that technological or economic limitations on the application of measurement technology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology.

The CAA contains a similar BACT definition, although the 1990 CAA amendments added "clean fuels" after "fuel cleaning or treatment" in the above definition. *See* CAA § 169(3).

On December 1, 1987, the EPA issued a memorandum describing the top-down approach for determining BACT. Memorandum from J. Craig Potter, Assistant Administrator for Air and Radiation, to EPA Regional Administrators regarding Improving New Source Review (NSR) Implementation (Dec. 1, 1987). In brief, the top-down approach provides that all available control technologies be ranked in descending order of control effectiveness. Each alternative is then evaluated, starting with the most stringent, until BACT is determined. The top-down approach consists of the following steps:

Step 1: Identify all available control technologies.

Step 2: Evaluate technical feasibility of options from Step 1 and eliminate options that are technically infeasible based on physical, chemical and engineering principles.

Step 3: Rank the remaining control technologies from Step 2 by control effectiveness, in terms of emission reduction potential.

Step 4: Evaluate the most effective controls from Step 3, considering economic, environmental and energy impacts of each control option. If the top option is not selected, evaluate the next most effective control option.

Step 5: Select BACT (the most effective option from Step 4 not rejected).

6.2 NO_X BACT Analysis for Internal Combustion Engines

A revised BACT determination for the main generator engines on the *Developer*, which have the potential to emit NO_X above the BACT limits established in the existing permit, was included in the modification application. However, the EPA has determined that the BACT analysis conducted in conjunction with this latest revision did not result in any significant changes to the respective control technology determinations for the NO_X emitting units of the *Developer*. This is as expected, since the applicant has not proposed to change any emissions units from those included in the existing permit issued on October 28, 2013 or to change the use or operation of these emission units. The detailed BACT analysis including NO_X control technologies and feasibility determinations can be found in the March 2014 modification application and in the original statement of basis for the existing permit (Permit No. OCS-EPA-R4012), which are available in the administrative record for this project, as discussed in Section 9.0 of this document.

As discussed above, results from the October 2013 source tests on the Developer's main generating engines demonstrated that the emissions of NO_X would exceed the BACT limit of 8.6 g/kW-hr established in the existing permit. Statoil proposed a revised BACT emission limit for NO_X of 12.30 g/kW-hr for the main generator engines on the *Developer* based on a 5% margin of compliance above the highest emission rate obtained during the source test. Based on our analysis of all test results, the EPA is proposing a BACT emission rate for each of the engines of 12.0 g/kW-hr, which is approximately two standard deviations above the average of the high load testing results. Given that there is a 24-hour averaging time and the units will be operating at variable load, the EPA believes well maintained engines will be able to achieve this emission rate. This BACT emission rate is within the range of the EPA's recent BACT determinations for engines of similar size and model year.

In addition to the short-term BACT emissions limit, annual emissions rate limits in tons per year have been added to the draft permit for the main generator engines which reflect calculations presented in the modification application.

The EPA refers interested parties to the administrative record for Permit No. OCS-EPA-R4012 for the EPA's original statement of basis/preliminary determination for this project and the comprehensive NO_X BACT analysis. These materials are available in the project's administrative record, as discussed in Section 9.0 of this document. The revised NO_X BACT emissions limits that were incorporated in this modified draft permit are given in the table below.

Table 6-1: Revised NO_X BACT Conclusions (Operating Scenario 1)

Emission Units	**Control Option**	**Short Term Emission Limit**	**Annual Emission Limit**
(8) Main Generator Engines (GEN-1 through GEN-8)	40 CFR part 94 Tier 2 Compliant Design (Turbocharger, Aftercooler, High Injection Pressure Fuel System, and Low NO_X Tuning)	12.0 g/kW-hr each engine (24-hour rolling average)	416.15 TPY combined eight engines (12-month rolling total)

6.3 VOC BACT Analysis for Internal Combustion Engines

Most VOCs found in diesel exhaust are the result of unburned fuel, although some are formed as combustion products. VOC compounds participate in atmospheric photochemical reactions which can result in the formation of ozone. For the purpose of PSD applicability, VOCs do not include methane, ethane, and other compounds that have negligible photochemical reactivity.

6.3.1 Step 1: Identify all Available Control Technologies

The applicant identified the following available VOC control technologies in their OCS permit modification application submitted in March 2014:

1. Diesel Oxidation Catalyst (DOC)
2. Catalyzed Diesel Particulate Filter (CDPF)
3. Flow Through Filter (FTF)
4. Engine Replacement
5. Tier 1 or 2 Certification
6. Good Combustion Practices
7. Ultra-Low Sulfur Diesel (USLD)

From other OCS projects, the EPA is aware of the following additional technology options:

8. 4-Way Catalyst Converter with Exhaust Gas Recirculation System
9. E-POD

6.3.2 Step 2: Eliminate Technically Infeasible Control Options

A summary of the rationale for either eliminating a technology from further consideration in the top-down BACT analysis for this project or for carrying it through the BACT analysis is listed below for the identified options.

Diesel Oxidation Catalyst (DOC), Catalytic Diesel Particulate Filter (CDPF), and Flow through Filter (FTF): These control technologies require sufficient exhaust temperatures to perform. The main generating engines operate under fluctuating, typically low, loads and the emergency generator and cementing unit engines operate intermittently by design. Therefore, none of the diesel engines onboard the *Developer* are able to sustain the constant steady state loads or temperatures necessary for control technology performance. These control technologies are also flow-through units that can cause pressure drops across the exhaust flow resulting in back pressure and plugging of the engine, which can create safety concerns. In addition, for internal combustion engines, these technologies have not been designed or tested on a scale comparable to the large main and emergency diesel engines. Although the applicant provided a cost analysis for installing DOC, CDPF, and FTF on the emergency generator engine, these analyses were not relied upon in EPA’s decision. The EPA agrees with the applicant that these control technologies are not technically feasible for the main generating engines, the emergency generator, and the cementing unit engines.

Engine Replacement (40 CFR part 1042 Tier 4 Compliant Engines): Based on engine specifications, the main generator engines on the *Developer* are classified as Category 2 marine engines under 40 CFR part 1042 Tier 3 and Tier 4 requirements. 40 CFR part 1042 does not require Tier 3 certification for Category 2 engines rated at or above 3,700 kW. Tier 4 certification requirements for similarly rated engines go into effect beginning with model years 2014-2015. After an independent search by the EPA, no comparable Tier 3 or Tier 4 certified marine engines that satisfy size, space, and weight restrictions on the vessel were identified. It has been established in previous Region 4 OCS permitting actions that the referenced restrictions must be met for engine replacements to avoid any possible safety risk from a loss of power. With no comparable engine on the market able to meet the lower Tier 3 or Tier 4 emission standards without the use of add-on control technology, the EPA agrees that this option is not considered to be technically feasible for the main generator engines.

Replacement of the emergency generator engine with a comparable 40 CFR 1042 Tier 3 or Tier 4 certified engine is considered technically feasible and is carried through the next step of the BACT analysis. Likewise, replacement of the cementing unit engines is considered technically feasible and is carried through the next step of the BACT analysis.

40 CFR 94 Tier 1 or 2 Certification: The main generator engines on the *Developer* are Category 2 marine engines subject to Tier 1 certification requirements under 40 CFR part 94. However, the certification documentation provided by the applicant indicates that the main generator engines meet the more stringent 40 CFR part 94 Tier 2 THC+NOX emission standard that is applicable to comparable 2007-2013 model year engines. Therefore, meeting this tier standard is considered technically feasible for control of VOC and is carried through the next step of the BACT analysis for the main generator engines.

The emergency generator engine located on the *Developer* is a Category 1 marine engine certified by the manufacturer to meet relevant 40 CFR part 89 Tier 1 nonroad compression ignition engine requirements for hydrocarbon emissions. Meeting this tier standard is considered technically feasible for control of VOC and is carried through the next step of the BACT analysis for the emergency generator engine.

The cement unit engines located on the *Developer* are certified to meet the 40 CFR part 94 Tier 2 marine engine standard for THC+NOx emissions of 7.2 g/kW-hr. Therefore, meeting this tier standard is considered technically feasible for control of VOC and is carried through the next step of the BACT analysis for the cementing unit engines.

4-Way Catalyst Converter with Exhaust Gas Recirculation System: The engines onboard the *Developer* will not sustain constant steady state loads or temperatures for a sufficient time necessary for high catalyst performance. Non-combustible chemical elements present in engine lube oils may also collect over time and damage the catalyst. Furthermore, based on information from Wärtsilä, this technology is in the developmental stage and is not available for this project. For these reasons, the EPA has determined that this technology is not technically feasible.

E-POD: This technology integrates selective catalytic reduction with a DOC or a CDPF. The EPA has determined that this technology is technically infeasible based on the rationale for elimination of DOC and CDPF technologies.

6.3.3 Step 3: Rank the Remaining Control Technologies by Effectiveness

The control options not eliminated as technically infeasible in Step 2 of the top-down BACT analysis were then ranked by effectiveness. Table 6-2 lists the control technologies that have not been ruled out as technically infeasible options. These options are then ranked by effectiveness.

Table 6-2: Step 3 Control Technologies Ranked by Effectiveness

Engine	Rank	Control Description	VOC Control Effectiveness
(8) Main Generator Engines (GEN-1 thru GEN-8)	1	40 CFR 94 Tier 2 compliant engines, use of ULSD, turbocharger, aftercooler, high injection pressure fuel system, and good combustion practices	Baseline
Emergency Generator Engine (EGEN)	1	Engine replacement and 40 CFR 1042 Tier 3 or 4 certification	56%
	2	40 CFR 89 Tier 1 compliant engine, use of ULSD, turbocharger, aftercooler, electronic fuel injection system, and good combustion practices	Baseline
(2) Cementing Unit Engines (CMU-1 and CMU-2)	1	Engine replacement and 40 CFR 1042 Tier 3 or 4 certification	22%
	2	40 CFR 94 Tier 2 certification, use of ULSD, turbocharger, aftercooler, and good combustion practices	Baseline

6.3.4 Step 4: Evaluate the Energy, Environmental and Economic Impacts

Engine Replacement and 40 CFR 1042 Tier 3 or 4 Certification for Emergency Generator Engine: In their March 2014 modification application, Statoil examined the cost effectiveness of replacing the emergency generator engine on the *Developer* with a comparable 40 CFR part 1042 Tier 4 certified engine. A comparable 2014 or 2015 model year replacement would ordinarily be required to meet the Tier 3 certification requirements. However, to remain conservative in the cost analysis, the applicant assumed that an appropriate Tier 4 compliant engine comparable in size to the emergency generator engine would be available and technically feasible. A VOC emissions control efficiency of approximately 56% was determined by comparing the annual average VOC emission factor for the existing emergency generator engine (0.43 g/kW-hr) to the Tier 4 non-methane hydrocarbons (NMHC) emission standard (0.19 g/kW-hr) that would apply to a comparable engine. The total capital cost for replacement of the emergency generator engine is estimated to be $5,644,136. Based on a 10-year engine lifespan and a 7% annual interest rate, the cost is estimated to be $808,441 on an annualized basis.

Statoil estimated that 10 days would be necessary to replace the engine and included the daily lease rate for the vessel in the cost analysis. Based on the emissions reduction potential (56%), Statoil estimates a VOC reduction of 0.020 tpy. As a result, the cost effectiveness was calculated to be $40,693,133 per ton of VOC emissions removed. The EPA concurs with the applicant that this is not cost effective.

Cost analysis calculations and supporting documentation are included in Appendix D of the March 2014 modification application.

Engine Replacement and 40 CFR 1042 Tier 3 or 4 Certification for Cement Unit Engines: In their March 2014 modification application, Statoil examined the cost effectiveness of replacing the cementing unit engines on the *Developer* with comparable 40 CFR part 1042 Tier 3 certified engines. A comparable 2014 or 2015 model year replacement would ordinarily be required to meet the current Tier 3 certification requirements. However, to remain conservative in the cost analysis, the applicant assumed that an appropriate Tier 3 engine meeting the more stringent part 1042 requirements for a 2018 model year engine would be available. A VOC emissions control efficiency of approximately 22% was determined by comparing the Tier 2 THC+NOx emission standard applicable to each of the existing cement unit engines (7.2 g/kW-hr) to the Tier 3 THC+NOx emission standard (5.6 g/kW-hr) that would apply to a Category 1 marine engine of a comparable engine. The total capital cost for replacement of the two cementing unit engines is estimated to be $309,185. Based on a 10-year engine lifespan and a 7% annual interest rate, the cost is estimated to be $44,021 on an annualized basis.

Statoil did not include a daily lease rate for the vessel in the cost analysis. Based on the emissions reduction potential (22%), Statoil estimates a VOC reduction of 0.042 tpy. As a result, the cost effectiveness was calculated to be $1,061,191/ton of VOC emissions. The EPA concurs with the applicant that this is not cost effective.

Cost analysis calculations and supporting documentation are included in Appendix D of the March 2014 modification application.

6.3.5 Step 5: Select BACT

After taking into account the energy, environmental, and economic impacts discussed above in Step 4 of the BACT analysis, the EPA determined that the control options summarized in Table 6-3 are BACT for diesel engines on the *Developer*. The BACT limits for VOC emissions from the main generator engines were established for low and high engine load scenarios (i.e., less than 55 percent and greater than or equal to 55 percent loads). In addition to the short-term BACT emissions limit, annual emissions rate limits in tons per year have been added to the draft permit for the main generator engines which reflect calculations presented in the modification application.

Table 6-3: VOC BACT Conclusions for Internal Combustion Engines

Emission Units	**Control Option**	**Short Term Emission Limit**	**Annual Emission Limit**	**Operating Limit**
Main Generator Engines (GEN-1 through GEN-8)	Use of main engines with 40 CFR 94 Tier 2 compliant design (including low NO_X tuning, turbocharger, after- cooler, and high injection pressure) and ULSD with good combustion practices based on current manufacturer recommendations.	2.15 g/kW-hr at < 55% loads for each engine (24-hour rolling average) ----------------- 1.73 g/kW-hr at ≥ 55% loads for each engine (rolling 24-hour average)	66.12 TPY combined eight engines (12-month rolling total)	__________
Emergency Generator Engine (EGEN)	Use of engine with 40 CFR 89 Tier 1 compliant design (including turbocharger, after cooler and electronic fuel injection) and ULSD with good combustion practices based on current manufacturer recommendations.	___________	_________	39 hours per year of planned operation time for routine testing and maintenance on a rolling 12-month average basis
Cementing Unit Engines (CMU-1 and CMU-2)	Use of engine with 40 CFR 94 Tier 2 compliant design and ULSD with good combustion practices.	___________	_________	300 combined hours per year on a rolling 12-month average basis

6.4 PM_{10}/$PM_{2.5}$ BACT Analysis for Internal Combustion Engines

Diesel particulate emissions are primarily products of incomplete combustion of diesel fuel and lubrication oil in the combustion chamber. BACT for PM_{10} and $PM_{2.5}$ is addressed concurrently since any control technology available for the control of $PM_{2.5}$ will also effectively control PM_{10}. The PM_{10} and $PM_{2.5}$ emissions represent 82.2% and 79.8% of total PM emissions, respectively, based on AP-42 factors.

6.4.1 Step 1: Identify all Available Control Technologies

The applicant identified the following available control technologies in their OCS permit modification application submitted in March 2014 which is contained in the administrative record described in Section 9.0 of this document:

1. Diesel Particulate Filter/Catalyzed Diesel Particulate Filter (DPF/CDPF)
2. Diesel Oxidation Catalyst (DOC)
3. Flow Through Filter (FTF)
4. Open/Closed Crankshaft Ventilation (OCV/CCV)
5. Engine Replacement
6. Engine Retooling (Engine Rebuild Kits)
7. Engine Derate
8. Alternative Lube Oils
9. Tier 1 or 2 Certification
10. LNE design including (turbocharger with after-cooler/high injection pressure/electronic fuel injection)
11. Good Combustion Practices
12. Ultra-low Sulfur Diesel

From other OCS projects, the EPA is aware of the following additional technology options:

13. E-POD Technology (on Large Combustion Engines and Third Party Engines)
14. 4-Way Catalyst Converter with Exhaust Gas Recirculation System

6.4.2 Step 2: Eliminate Technically Infeasible Control Options

A summary of the rationale for either eliminating a technology from further consideration in the top-down BACT analysis for this project or for carrying it through the BACT analysis is listed below for the identified options.

Diesel Oxidation Catalyst (DOC), Catalytic Diesel Particulate Filter (CDPF), and Flow through Filter (FTF): These control technologies require sufficient exhaust temperatures to perform. The main generating engines operate under fluctuating, typically low, loads and the emergency generator and cementing unit engines operate intermittently by design. Therefore, none of the diesel engines onboard the *Developer* are able to sustain the constant steady state loads or temperatures necessary for control technology performance. These control technologies are also flow-through units that can cause pressure drops across the exhaust flow resulting in back pressure and plugging of the engine, which can create safety concerns. In addition, for internal combustion engines, these technologies have not been designed or tested on a scale comparable to the large main generator and emergency diesel engines.

The smaller cement unit engines operate in a hazardous area that requires specially certified equipment to meet safety standards. CDPF, DOC or FTF systems that meet the hazardous zone requirements were not identified by the applicant or by the EPA after an independent search. Although the applicant provided a cost analysis for installing DOC, CDPF, and FTF on the emergency generator engine, these analyses were not relied upon in the EPA's decision. The EPA agrees with the applicant that these control technologies are not technically feasible for the main generating engines, the emergency generator, and the cementing unit engines.

Engine Replacement (40 CFR part 1042 Tier 3 or 4 Compliant Engines): Based on engine specifications, the main generator engines on the *Developer* are classified as Category 2 marine engines under 40 CFR part 1042 Tier 3 and Tier 4 requirements. 40 CFR part 1042 does not require Tier 3 certification for Category 2 engines rated at or above 3,700 kW. Tier 4 certification requirements for similarly rated engines go into effect beginning with model years 2014-2015. After an independent search by the EPA, no comparable marine engines that satisfy size, space, and weight restrictions on the vessel were identified that are certified to Tier 3 or Tier 4 standards. It has been established in previous Region 4 OCS permitting actions that the referenced restrictions must be met for engine replacements to avoid any possible safety risk from a loss of power. With no comparable engine on the market able to meet the lower Tier 3 or Tier 4 emission standards without the use of add-on control technology, the EPA agrees that this option is not considered to be technically feasible for the main generator engines.

Replacement of the emergency generator engine with a comparable 40 CFR 1042 Tier 3 or Tier 4 certified engine is considered technically feasible and is carried through the next step of the BACT analysis. Likewise, replacement of the cementing unit engines is considered technically feasible and is carried through the next step of the BACT analysis.

40 CFR 94 Tier 1 or 2 Certification: The main generator engines on the *Developer* are Category 2 marine engines certified by the manufacturer to meet Tier 1 requirements under 40 CFR part 94. Tier 1 certification requirements do not include a PM emissions limitation. PM emissions were measured in the October 2013 source testing from the main generator engines. The results indicate that emissions from the main generator engines would likely meet the applicable Tier 2 PM emission standard. However, there was not sufficient data to definitively establish compliance. Therefore, replacement of these engines with Tier 2 certified engines is considered technically feasible and is carried through the next step of the BACT analysis.

The emergency generator engine is a Category 1 marine engine certified by the manufacturer to meet relevant 40 CFR part 89 Tier 1 nonroad compression ignition engine requirements for PM emissions. Since 40 CFR part 1042 Tier 3 certification requirements apply for engine model years between 2012 and 2015, Statoil opted to examine replacement of this engine with a new unit meeting this requirement as opposed to a Tier 2 compliant model. This is considered technically feasible for control of $PM_{10}/PM_{2.5}$ and is carried through the next step of the BACT analysis for the emergency generator engine.

The cement unit engines are certified to meet the 40 CFR part 94 Tier 2 marine engine standard for PM emissions. Therefore, meeting this tier standard is considered technically feasible for control of $PM_{10}/PM_{2.5}$ and is carried through the next step of the BACT analysis for the cementing unit engines.

Open Crankcase/Closed Crankcase Ventilation: Crankcase ventilation systems are intrinsic to an engine's design. The main generator, emergency generator, and cement unit engines on the *Developer* are constructed with OCV systems that use centrifugal force or knockout-type equipment for PM control. Therefore, use of this control technology is carried forward in the BACT analysis for these engines.

Engine Rebuild Kits: According to the manufacturer of the engine rebuild kits, Clean Cam Technology Systems, LLC, these kits are only available for two-stroke Detroit Diesel engines, model series 71 and 92. None of the main generator, emergency generator, or cement unit engines on the *Developer* are two-stroke engines. Therefore, the EPA does not consider this technology to be feasible for these engines.

Engine Derate: While derating the engines can potentially reduce NO_X emissions, it would likely result in higher particulate emissions due to decreased combustion temperatures and more incomplete combustion within the engine. Furthermore, derating an engine can decrease available power to the engines reducing the vessel's ability to maintain correct positioning during storms and loop current events and impairing the performance of the auxiliary engines during drilling activities. This would cause an unacceptable safety risk on the drilling vessels. Therefore, the EPA does not consider this control technology technically feasible.

Alternative Lube Oils: Statoil conducted a review of the available literature regarding use of alternative lube oils in diesel engines, which is included in the March 2014 modification application. Currently, there is a lack of information available to definitively assess the use of alternative lube oils or quantify emissions reductions with respect to PM emissions control. Therefore, the EPA does not consider the use of alternative lube oils to be a technically feasible demonstrated control for these engines at this time.

4-Way Catalyst Converter with Exhaust Gas Recirculation System: The engines onboard the *Developer* will not sustain constant steady state loads or temperatures for a sufficient time necessary for high catalyst performance. Non-combustible chemical elements present in engine lube oils may also collect over time and damage the catalyst. Furthermore, based on information from Wärtsilä, this technology is in the developmental stage and is not available. For these reasons, the EPA has determined that this technology is not technically feasible.

E-POD: This technology integrates selective catalytic reduction with a DOC or a CDPF. The EPA has determined that this technology is technically infeasible based on the rationale for elimination of DOC and CDPF technologies.

6.4.3 Step 3: Rank the Remaining Control Technologies by Effectiveness

The control options not eliminated as technically infeasible in Step 2 of the top-down BACT analysis were then ranked by effectiveness. Table 6-4 lists the control technologies that have not been ruled out as technically infeasible options. These options are then ranked by effectiveness for the main generator engines, the emergency generator engines, and the cementing unit engines.

Table 6-4: Step 3 Control Technologies Ranked by Effectiveness

Engine	Rank	Control Description	$PM_{10}/PM_{2.5}$ Control Effectiveness
(8) Main Generator Engines (GEN-1 thru GEN-8)	1	Engine replacement and 40 CFR 94 Tier 2 certification for PM	4%
	2	40 CFR 94 Tier 2 compliant engines, use of ULSD, OCV, turbocharger, aftercooler, high injection pressure fuel system, and good combustion practices	Baseline
Emergency Generator Engine (EGEN)	1	Engine replacement and 40 CFR 1042 Tier 3 or 4 certification	87%

	2	40 CFR 89 Tier 1 compliant engine, use of ULSD, OCV, turbocharger, aftercooler, electronic fuel injection system, and good combustion practices	Baseline
(2) Cementing Unit Engines (CMU-1 and CMU-2)	1	Engine replacement and 40 CFR 1042 Tier 3 or 4 certification	50%
	2	40 CFR 94 Tier 2 certification, use of ULSD, OCV, turbocharger, aftercooler, and good combustion practices	Baseline

6.4.4 Step 4: Evaluate the Energy, Environmental and Economic Impacts

Engine Replacement and 40 CFR 94 Tier 2 Certification for Main Generator Engines: In their March 2014 modification application, Statoil examined the cost effectiveness of replacing all eight of the main generator engines on the *Developer* with comparable 40 CFR part 94 Tier 2 certified engines.

A PM emissions control efficiency of approximately 4% was determined by comparing the maximum annual average PM emission factor for the existing engines (0.52 g/kW-hr) to the Tier 2 emission standard (0.50 g/kW-hr) that would apply to comparable engines. The total capital cost for replacement of the main generator engines is estimated to be $25,231,200. Based on a 10-year engine lifespan and a 7% annual interest rate, the cost is estimated to be $3,592,355 on an annualized basis.

Statoil estimated that 30 days would be necessary to replace the engines and included the daily lease rate for the vessel in the cost analysis. Based on the emissions reduction potential (4%), Statoil estimates a PM_{10} reduction of 0.512 tpy and a $PM_{2.5}$ reduction of 0.497 tpy. As a result, the cost effectiveness was calculated to be $7,013,456 per ton of PM_{10} emissions and $7,227,983 per ton of $PM_{2.5}$ emissions removed. Although the EPA calculated slightly different costs based on information in the analysis ($7,016,318 tpy and $7,228,078, respectively), the EPA concurs with the applicant that this option is not cost effective for the main generator engines.

Cost analysis calculations and supporting documentation are included in Appendix D of the March 2014 modification application.

Engine Replacement and 40 CFR 1042 Tier 3 or 4 Certification for Emergency Generator Engine: In their March 2014 modification application, Statoil examined the cost effectiveness of replacing the emergency generator engine on the *Developer* with a comparable 2012 through 2015 model year 40 CFR part 1042 Tier 3 certified engine. Tier 4 certification is not required prior to 2016 engine model years. To remain conservative in their cost estimate, Statoil assumed that an engine comparable in size and specifications to the emergency generator engine would be available and technically feasible. A PM emissions control efficiency of approximately 87% was determined by comparing the annual average PM emission factor for the existing emergency generator engine (0.30 g/kW-hr) to the Tier 4 emission standard (0.04 g/kW-hr) that would apply to a comparable engine. The total capital cost for replacement of the emergency generator engine is estimated to be $5,644,136. Based on a 10-year engine lifespan and a 7% annual interest rate, the cost is estimated to be $808,441 on an annualized basis.

Statoil estimated that 10 days would be necessary to replace the engine and included the daily lease rate for the vessel in the cost analysis. Based on the emissions reduction potential (87%), Statoil estimates a PM_{10} reduction of 0.0176 tpy and a $PM_{2.5}$ reduction of 0.017 tpy. As a result, the cost effectiveness was calculated to be $46,039,050 per ton of PM_{10} emissions and $47,446,719 per ton of $PM_{2.5}$ emissions removed. Although the EPA calculated slightly different costs based on information in the analysis ($45,934,147 tpy and $47,555,352, respectively), the EPA concurs with the applicant that this option is not cost effective for the emergency generator engine.

Cost analysis calculations and supporting documentation are included in Appendix D of the March 2014 modification application.

Engine Replacement and 40 CFR 1042 Tier 3 or 4 Certification for Cement Unit Engines: In their March 2014 modification application, Statoil examined the cost effectiveness of replacing the cementing unit engines on the *Developer* with comparable 40 CFR part 1042 Tier 3 certified engines. A comparable 2014 through 2017 model year replacement would ordinarily be required to meet the current Tier 3 certification requirements. However, to remain conservative in the cost analysis, the applicant assumed that an appropriate Tier 3 engine meeting the more stringent part 1042 requirements for a 2018 model year engine would be available. A PM emissions control efficiency of approximately 50% was determined by comparing the Tier 2 emission standard applicable to each of the existing cement unit engines (0.20 g/kW-hr) to the Tier 3 emission standard (0.10 g/kW-hr) that would apply to a Category 1 marine engine of a comparable 2018 model year engine. The total capital cost for replacement of the two cementing unit engines is estimated to be $309,185. Based on a 10-year engine lifespan and a 7% annual interest rate, the cost is estimated to be $44,021 on an annualized basis.

Statoil did not include a daily lease rate for the vessel in the cost analysis. Based on the emissions reduction potential (50%), Statoil estimates a PM_{10} reduction of 0.0101 tpy and a $PM_{2.5}$ reduction of 0.0098 tpy. As a result, the cost effectiveness was calculated to be $4,342,888 per ton of PM_{10} emissions and $4,475,674 per ton of $PM_{2.5}$ emissions removed. Although the EPA calculated slightly different costs based on information in the analysis ($4,358,514 tpy and $4,491,938, respectively), the EPA concurs with the applicant that this option is not cost effective for the cementing unit engines.

Cost analysis calculations and supporting documentation are included in Appendix D of the March 2014 modification application.

6.4.5 Step 5: Select BACT

After taking into account energy, economic and environmental impacts discussed above in Step 4 of the BACT analysis, the EPA determined that the control options summarized in Table 6-5 are BACT for diesel engines on the *Developer*. The BACT limits for PM_{10} and $PM_{2.5}$ were established for low and high engine load scenarios (i.e., less than 55 percent and greater than or equal to 55 percent loads). In addition to the short-term BACT emissions limit, annual emissions rate limits in tons per year have been added to the draft permit for the main generator engines which reflect calculations presented in the modification application.

Table 6-5: BACT Conclusions

Emission Units	Control Option	Short Term Emission Limit	Annual Emission Limit	Operating Limit
Main Generator Engines (GEN-1 through GEN-8)	Use of main engines with 40 CFR 94 Tier 2 compliant design (including low NO_X tuning, turbocharger, after-cooler, and high injection pressure) and ULSD with good combustion practices based on current manufacturer recommendations.	PM_{10}: 0.50 g/kW-hr at < 55% loads for each engine (24-hour rolling average) $PM_{2.5}$: 0.49 g/kW-hr at < 55% loads for each engine (24-hour rolling average) ----------------- PM_{10}: 0.26 g/kW-hr at ≥ 55% loads for each engine (24-hour rolling average) $PM_{2.5}$: 0.26 g/kW-hr at ≥ 55% loads for each engine (24-hour rolling average)	PM_{10}: 12.81 TPY combined eight engines (12-month rolling total) $PM_{2.5}$: 12.43 TPY combined eight engines (12-month rolling total)	____________
Emergency Generator Engine (EGEN)	Use of engine with 40 CFR 94 Tier 1 compliant design (including turbocharger, after cooler and electronic fuel injection) with good combustion practices based on current manufacturer recommendations.	_____________	______________	39 hours per year of planned operation time for routine testing and maintenance on a rolling 12-month average basis
Cementing Unit Engines (CMU-1 and CMU-2)	Use of engine with 40 CFR 94 Tier 2 compliant design and good combustion practices.	_____________	______________	300 combined hours per year on a rolling 12-month average basis

6.5 BACT Analysis for Storage Tanks

The *Developer* has various storage tanks subject to BACT review for emissions of VOC. These tanks provide storage for diesel fuel, helicopter fuel, and waste oil. The following tanks are included in this analysis: FO CMV ST, FO MOB ST, FO SER ST 1 and 2, FO SET ST 3 and 4, FO ST 1 through 4, FO LB ST 1 through 4, FO EGEN ST, AV ST 1 through 3, and WO ST 1 and 2. The fuel in these tanks will generate VOC emissions resulting from both breathing and working (*i.e.*, loading) losses.

Step 1: Identify all available control technologies

The applicant identified the following available control technologies in their OCS permit application submitted in March 2014:

1. Vapor Collection System and Control Device
2. Internal Floating Roof or External Floating Roof
3. Adsorption System
4. Fixed Roof with Submerged Fill Pipe

The EPA did not identify any additional control technologies that are appropriate for use on storage tanks on the *Developer*.

Step 2: Eliminate technically infeasible control options

After analyzing the above control technologies, all of the options were eliminated as technically infeasible for control of VOC emissions from the tanks. Below is a summary of the reasons for eliminating each of the above options from further consideration in the top-down BACT analysis for this project. For detailed descriptions and references please refer to the application submitted to the EPA in March 2014.

Vapor Recovery Units, Adsorption Systems, and Internal or External Floating Roofs: Installation of vapor recovery units, adsorption systems and internal or external floating roofs are all considered technically infeasible due to space constraints on the vessel. Furthermore, adsorption systems are generally not effective for controlling low concentrations of VOC generated by diesel storage tanks. Floating roofs are not effective for controlling VOC emissions from stored liquids of low vapor pressures, such as diesel.

Submerged Fill Systems: The Pontoon Fuel Oil Tanks 1 through 4 (FO ST 1 through 4) and the Upper Hull Fuel Oil Tanks 1 and 2 (FO SER ST 1 and 2) are equipped with this technology. However, it is not technically feasible to install submerged fill systems on existing *Developer* storage tanks that were not initially designed with this technology due to space constraints and the potential for overloading the existing mechanical pump feed system with increased pressure. In general, these systems are not installed on storage tanks of low vapor pressure and low capacity as is the case with the remaining storage tanks.

Steps 3/4/5: Rank/Evaluate/Determine BACT

Based on a review of the available control technologies, the EPA has determined that BACT is use of good maintenance practices in accordance with the most recent manufacturer's specifications for all storage tanks on the drilling vessel at the time that project activities are conducted under this permit and the use of a submerged fill system for tanks FO ST 1 through 4 and FO SER ST 1 and 2. This will limit tank leakage and excessive VOC emissions. The amount of VOC emissions emitted from the tanks is also contingent upon both the fuel type and the amount of fuel. Therefore, the applicant will maintain records of the tank identification, volume, and fuel type stored. The applicant will calculate emissions from the storage tanks using EPA's TANKS 4.0.9d program.

6.6 BACT Analysis for Cement and Barite Handling Operations

The *Developer* has cement and barite mixing and transfer operations (CEMENT-BARITE) subject to BACT review for emissions of PM_{10} and $PM_{2.5}$.

Step 1: Identify all available control technologies

Statoil identified dust collectors with or without the use of an enclosed conveyance system as the only available control technology in their OCS permit application submitted in March 2014. The EPA did not identify any additional control technologies that are appropriate for use with the cement/barite operations on the *Developer*.

Step 2: Eliminate technically infeasible control options

The applicant determined that the use of a cyclone dust collector in an enclosed pneumatic conveyance system with the exhaust routed underwater is technically feasible.

Steps 3/4/5: Rank/Evaluate/Determine BACT

Based on a review of the available control technologies, the EPA has determined that BACT is use of the existing enclosed conveyance system with cyclonic dust collector and underwater exhaust. The permittee shall also use best management practices such as proper maintenance and operation of the enclosed pneumatic conveyance dust collector system based on the most recent manufacturer's specifications for the system issued at the time that project activities are conducted under this permit, performance of a daily visual check of the dust collector system, and maintenance of a daily inspections and system maintenance record.

6.7 BACT Analysis for Mud Degassing

The *Developer* has mud degassing operations (MUD) subject to BACT review for emissions of VOCs.

Step 1: Identify all available control technologies

The application states that a review of the RBLC database did not reveal any potential control technologies to capture and control fugitive emissions from the mud degassing operations and no VOC control technologies are applicable. The EPA did not identify any additional control technologies that are appropriate for use with the mud degassing operations on the *Developer*.

Step 2: Eliminate technically infeasible control options

There were no control technologies identified in Step 1.

Steps 3/4/5: Rank/Evaluate/Determine BACT

Based on a review of the available control technologies, the EPA has determined that BACT for VOC emissions from mud degassing is proper maintenance and operation of all units associated with this process based on the most recent manufacturer's specifications for the equipment issued at the time that project activities are conducted under this permit.

6.8 BACT Analysis for Painting Operations

The *Developer* has painting operations (PAINT) subject to BACT review for emissions of VOC and $PM_{10}/PM_{2.5}$.

Step 1: Identify all available control technologies

The application states that a review of the RBLC database did not reveal any potential control technologies for emissions from the painting operations aboard the *Developer*. However, Statoil acknowledges that transfer efficiency is key in minimizing emissions from painting activities. Information included in the application indicates that a high transfer efficiency (> 65%) is possible using the paint spraying equipment currently in use on the *Developer*. Additional information supplied to the EPA by Statoil via email on June 23, 2014 indicates that the model of paint sprayer in use on the *Developer* is a high volume low pressure unit designed to attain high transfer efficiencies. Attainment of actual transfer efficiencies approaching the potential efficiency is highly dependent on equipment operators following manufacturer recommended practices and procedures. The paint sprayer model currently in use on the drilling vessel or sprayers of similar efficiency ratings will be used while conducting any spray coating under this permit.

The EPA is also aware of a number of best management practices that can reduce painting related emissions, including but not limited to limiting the amount of painting that is performed on the vessel while conducting exploratory drilling activities under this permit; use of paint rollers instead of sprayers where practical; down spraying of paint where possible; use of a containment system such as a shroud or a barrier around the section of the drillship being painted whenever practical to reduce airborne particulate matter; proper storage of coatings and thinners in appropriately labeled, non-leaking containers; and maintenance of material safety data sheet information for all paints and thinners used while conducting painting activities under this permit.

Step 2: Eliminate technically infeasible control options

Use of the identified strategies in step 1 is considered to be technically feasible.

Steps 3/4/5: Rank/Evaluate/Determine BACT

Based on a review of the available control technologies, the EPA has determined that BACT for VOC and PM_{10}/PM_2 emissions from painting are paint sprayer transfer efficiency requirements, limitation of paint spraying, and best management practices as described in step 1.

6.9 BACT Analysis for Welding Operations

The *Developer* has welding operations (WELD) subject to BACT review for emissions of PM_{10} and $PM_{2.5}$.

Step 1: Identify all available control technologies

The applicant identified the limitation of electrode usage as the only available control technology in the modification application submitted in March 2014. The EPA also considers the use of best management practices a control technology. This would include, but not be limited to, following the most recent manufacturer's specifications for all equipment used in welding operations at the time that project activities are conducted under this permit.

Step 2: Eliminate technically infeasible control options

Of the available control technologies identified in step 1, both are considered technically feasible.

Steps 3/4/5: Rank/Evaluate/Determine BACT

Based on a review of the available control technologies, the EPA has determined that BACT is best management practices including following the most recent manufacturer's specifications for all equipment used in welding operations issued at the time that project activities are conducted under this permit. The permittee shall maintain an accurate record of the types and quantity (in pounds) of welding rods used on a rolling 12-month basis for the purpose of calculating actual emissions

6.10 BACT Analysis for Piping Fugitive Emissions

Statoil identified potential piping fugitive VOC emissions in the BACT analysis portion of their permit application. However, based on similar permit applications, the EPA has determined that BACT is limited to good maintenance practices to minimize fugitive emissions, including minimizing the release of emissions from valves, pump seals, and connectors; daily visual inspections of the components; and prompt repair of leaking components. The applicant will report any leaks and corrective action taken.

7.0 Summary of Air Quality Impact Analyses

7.1 Required Analyses

The PSD rules at 40 CFR § 52.21(k) require the permit applicant to demonstrate that, for all regulated air pollutants that would be emitted at or in excess of the significant emissions rates provided in 40 CFR § 52.21(b)(23)(i), the allowable emission increases from a proposed new major stationary source or major modification, in conjunction with all other applicable emission increases or reductions at the source, would not cause or contribute to a violation of any NAAQS nor cause or contribute to a violation of any applicable "maximum allowable increase" over the baseline concentration in any area (known as PSD increments).[3] The ambient air quality impact analysis must be based on air quality models, databases, and other requirements specified in 40 CFR part 51, Appendix W, Guideline on Air Quality Models.

As discussed in Section 4.0 above, Statoil requested revised BACT limits for NO_X and new BACT limits for PM_{10}, $PM_{2.5}$, and VOC based on October 2013 source testing which indicates that potential emissions from the *Developer* are above the PSD significant emission rates for PM_{10}, $PM_{2.5}$, and VOC and that emissions of NO_X are greater than those anticipated at the time that Statoil submitted its original

[3] The maximum allowable PSD increments are listed in 40 CFR § 52.21(c).

permit application. NO_X is a measured pollutant for NO_2 and ozone. Therefore, the PM_{10}, $PM_{2.5}$, NO_2 and ozone NAAQS; and the PM_{10}, $PM_{2.5}$, and NO_2 PSD increments are relevant to the air quality impact assessment.

As required by the May 8, 2008, final rules governing NSR implementation for fine particulate matter, 73 Fed. Reg. 28,321 (May 16, 2008), PSD permits must address directly emitted $PM_{2.5}$ as well as the pollutants responsible for secondary formation of $PM_{2.5}$ which include SO_2, NO_X, VOC, and ammonia. Therefore, Statoil must address compliance with the 24-hour and annual $PM_{2.5}$ NAAQS considering both direct emissions and secondary contributions.

Under 40 CFR § 52.21(m), a PSD permit application must include an air quality analysis in connection with the demonstration required by 40 CFR §52.21(k). For each pollutant for which a NAAQS or PSD increment exists, 40 CFR § 52.21(m)(1)(iv) requires the analysis to include at least one year of pre-construction ambient air quality monitoring data, unless the EPA approves a shorter monitoring period (not less than four months). 40 CFR § 52.21(i)(5)(i) allows exemption from the requirement for pre-construction ambient monitoring if the net emissions increase of a pollutant from the proposed source or modification would cause air quality impacts less than the ambient monitoring thresholds (i.e., Significant Monitoring Concentrations) listed in 40 CFR § 52.21(i)(5)(i), which are provided in Table 7-1[4]. 40 CFR § 52.21(m)(2) requires post-construction ambient air quality monitoring if the EPA determines it is necessary to determine the effect that emissions from the source or modification may have on air quality.

An additional impact analysis is required by 40 CFR § 52.21(o), including an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the proposed project, or that would occur as a result of any commercial, residential, industrial and other growth associated with the source. Analysis for vegetation having no significant commercial or recreational value is not required.

For sources impacting Federal Class I areas,[5] 40 CFR § 52.21(p) requires the EPA to consider any demonstration by the Federal Land Manager (FLM) that emissions from the proposed source would have an adverse impact on air quality related values, including visibility impairment. If the EPA concurs with the demonstration, the rules require that the EPA shall not issue the PSD permit.

Since the modifications associated with this revised permit do not change the current permitted Operating Scenario 2 for the drillship Transocean *Discoverer Americas*, the required air quality impact analyses only addresses the revised Operating Scenario 1 for the Maersk *Developer* drilling vessel and associated support vessels.

7.2 PSD Class II Air Quality Impact Assessment

An air quality impact assessment was performed for the revised operation of the Maersk *Developer* deepwater drilling vessel and associated support vessels. The modeled operating scenario was that which produced the worst-case impact.

[4] Due to the recent vacatur of the its significant monitoring concentration for $PM_{2.5}$ (see Section 7.2), this exemption is not aplicable for $PM_{2.5}$.

[5] Class I areas are defined in 40 CFR § 52.21(e). Mandatory Class I areas (which may not be redesignated to Class II or III) are international parks, national wilderness areas larger than 5,000 acres, memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres.

As discussed in Section 4.0, the estimates of maximum annual emissions of all pollutants from the *Developer* drilling vessel and associated supporting vessels resulted in estimated emissions of PM_{10}, $PM_{2.5}$, VOC, and NO_X greater than the PSD significant emissions rate. Hence, PM_{10}, $PM_{2.5}$, and NO_X are subject to ambient impact assessment. The VOC and NO_X pollutants are measured pollutants for ozone and precursors for $PM_{2.5}$. Therefore, impact assessments are also provided for ozone and secondary $PM_{2.5}$.

The modeling procedures took into consideration the January 22, 2013 decision by the federal Court of Appeals for the District of Columbia Circuit (D.C. Circuit) concerning use of the $PM_{2.5}$ significant monitoring concentration (SMC) and significant impact levels (SIL) as the basis for exemption from pre-construction air quality monitoring and cumulative NAAQS and PSD increment compliance modeling. *See Sierra Club v. EPA*, 705 F.3d 458 (D.C. Cir. 2013). The D.C. Circuit vacated and remanded the $PM_{2.5}$ SILs. Accordingly, project impacts less than the SILs cannot serve as the sole justification for eliminating cumulative NAAQS and PSD increment compliance modeling. While permit applicants may continue to use the $PM_{2.5}$ SILs in their analysis, they must provide additional information and justification to support a conclusion that a project's impacts will not cause or contribute to a NAAQS or PSD increment exceedance.

The court also vacated the $PM_{2.5}$ SMC. As a result of the court's decision, project impacts less than the SMC can no longer be used to exempt the project from pre-construction ambient air quality monitoring. However, permit applicants may use existing air quality observations in lieu of pre-construction monitoring if supporting information demonstrates that the existing ambient air quality data provides representative or conservative ambient concentrations for the impact area.

The ambient impact modeling was performed using dispersion and transport models and modeling techniques that follow the EPA regulatory guidelines (*see* 40 CFR Part 51, Appendix W) and applicable guidance memorandum (*see* Support Center for Atmospheric Modeling (SCRAM); http://www.epa.gov/scram001/).

Since the proposed drilling will occur at several locations, the worst case emissions were assumed to be located at the drilling site where the greatest onshore and nearshore impacts could occur [Note: Same location as used for both the *Discoverer Americas* and *Developer* drilling vessels in the original permit application.]. The OCS project impact area for the Class II area analysis, the area containing modeling receptors, was established 25 nautical miles from any state's seaward boundary, extending shoreward until the project's estimated impact is less than the significant impact level. For this project the nearest Class II area receptor is more than 50 km from the closest drilling location.

7.2.1 Air Quality Model Selection

Because the closest Class II area receptor is more than 50 km from the nearest proposed drilling location, the air quality impact analyses involve long-range transport and dispersion conditions. The EPA's preferred model for long-range transport assessments (CALPUFF/CALMET modeling system Version 5.8 (release 070623)) was selected to estimate potential impacts in the OCS Class II area. It should be noted that this same EPA-preferred long-range transport and dispersion model is appropriate for the PSD Class I impact assessment. In addition, the Class II coherent plume visibility assessment was performed using the VISCREEN model (Version 88341). Figure 7-1 provides the modeling domain used in the PSD Class II and Class I assessments as well as locations of other significant features (*e.g.*, nearest PSD Class I area).

Figure 7-1 CALPUFF Modeling Domain

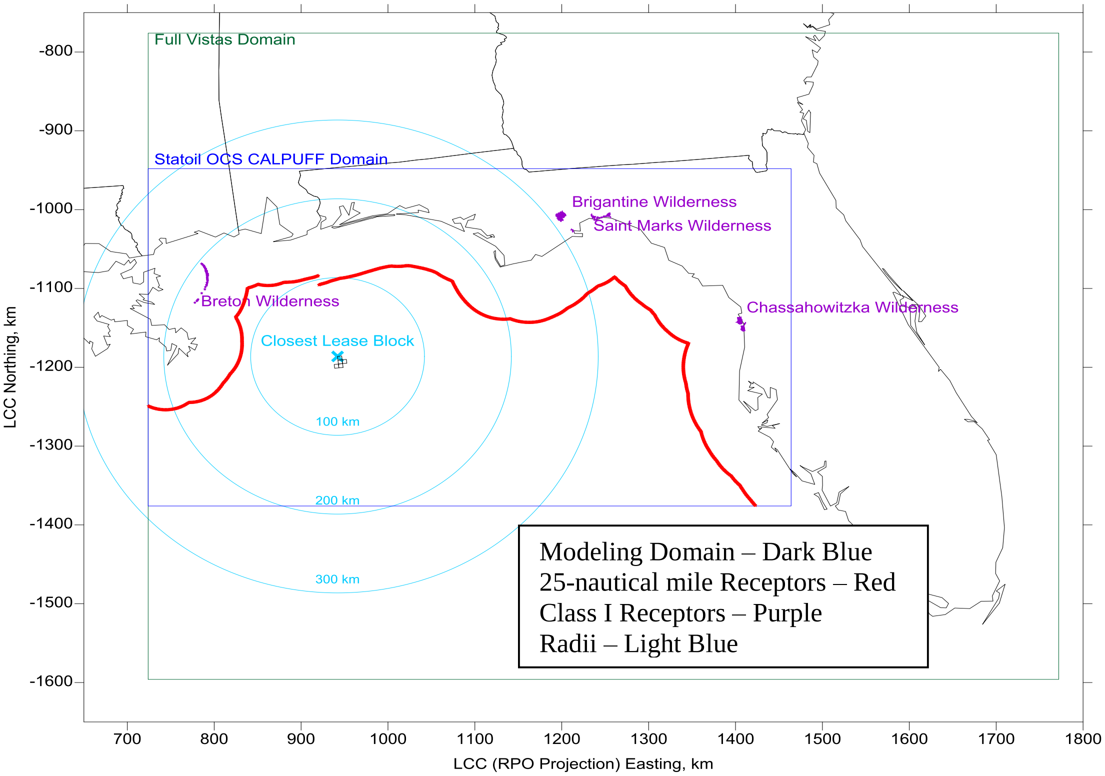

Image reproduced from the Revised Air Quality Impact Assessment dated June 2013 from ENVIRON.

7.2.2 Characteristics of Modeled Operational Scenarios

The primary PM_{10}, $PM_{2.5}$, and NO_X emission sources associated with the proposed exploration drilling activities are the diesel-fired engines on the drilling vessel. Additionally, the OCS air regulations define the OCS source to include emissions from vessels servicing the OCS sources while en route to and from the source when within 25 nautical miles of the drilling operation. Therefore, the impacts from the associated fleet of vessels that support the primary drilling activity were included.

The *Developer* and support vessel emission sources include the following:

- Main Diesel Generator Engines (8),
- Emergency Generator Engine (1),
- Cementing Unit Diesel Engines (2),
- Life Boat Engines (4),
- Rescue Boat Engine (1),
- Fuel Storage Vessels,
- Fugitives Emissions (diesel fuel system),
- Support Vessels (e.g., crew boats),
- Cement and Barite Handling Activities, and
- Painting and Welding Activities.

The basis for the maximum short-term (1 to 24 hour) and long-term (annual) emission rates modeled for these sources are discussed below.

The *Developer* is a self-powered, dynamically positioned semi-submersible drilling vessel with pontoon structures below the water surface and a platform above the surface. The drilling vessel uses a computer controlled sensor system to maintain position and heading over its location using the vessel's propellers and thrusters. The *Developer* drilling vessel requires no towing or anchoring vessels as part of its fleet. Because of the long distance to the nearest modeled receptor, the vessel orientation and building downwash considerations should not significantly affect the modeled impacts.

Multiple operating scenarios for the drilling vessel were considered including a range of emissions and release parameters (including partial loads) and varying locations of associated support vessels. These scenarios were evaluated to determine which scenario would result in maximum short-term and long-term impacts at the modeled receptors. The following described operating scenarios were determined to produce the worst-case impacts.

For the *Developer* operational scenarios, two sets of emission rates were developed; short-term and long-term rates. The short-term emission rates were used for the following assessments, as applicable:

- Class II 1-hour NO_2 SIL (NAAQS),
- Class I and II 24-hour PM_{10} and $PM_{2.5}$ SIL (NAAQS and PSD Increment), and
- Class I and II visibility.

The long-term emission rates were used for the remaining assessments:

- Class I and Class II annual NO_2 SIL (NAAQS and PSD Increment),
- Class I and II annual PM_{10} and $PM_{2.5}$ SIL (NAAQS and PSD Increment), and
- Class I annual Nitrogen deposition rate.

The *Developer's* modeled maximum short-term (1-hour to 24-hour) emissions are based on:

- Five main generator engines operating at 60% load and auxiliary equipment (i.e., 1 emergency generator engine, 4 life boat engines, 1 fast rescue boat and 2 cementing unit engines) operating at 100% load.
- Three Offshore Support Vessels (OSV) with 2 main engines on each at 75% load.
- One crew boat with 4 engines each at 75% load.
- These vessel/boat operations also have daily fuel usage limits: All OSV operations are limited to 13,058 gallons diesel fuel per day while the crew boat diesel fuel usage is limited to 6,620 gallons when operating within 25 nautical miles of the drilling vessel.

The *Developer's* annual modeled emissions are based on:

- Eight main generator engines operating at 12 varying operational modes for 180 days;
- All auxiliary equipment operating at 100% load [1 emergency (39 hours), 4 life boat engines (12 hours), 1 fast rescue (12 hours), and 2 cement units (300 hours total)] for the indicated permitted time periods in the 180-day campaign;.
- One OSV with two main engines on each at 100 % load for 2,570 hours per 180-day campaign;
- One crew boat with 4 engines and 2 generator engines at 100% load each for 618 hours per 180-day campaign; and

- Although a 180-day drilling campaign is the planned annual operations, the length of the campaign will be fuel limited. These limits are: based on all auxiliary equipment at 100% load, and support vessels based on the maximum engine operation and fuel use for the proposed annual run time (*i.e.*, crew boat at 618 hours/year resulting in 235,176 gallons of diesel fuel per year and OSV at 2,570 hours/year resulting in 621,468 gallons of diesel fuel per year for operation within 25 nautical miles of the drilling vessel).The *Developer* exploratory drilling operations will be limited to 2,459,150 gallons diesel fuel per year.

Statoil is requesting authorization for the *Developer* drilling vessel, and its associated support fleet, to operate in any of Statoil's lease blocks located within the eastern Gulf of Mexico (EGOM) as listed in Section 2.2 of this document and any additional lease block in the EGOM whose nearest drilling location is at least 176 km (95 nautical miles) from the three PSD Class I area if concern in this application, more than 300 km (162 nautical miles) from any other PSD Class I area, and more than 93 km (50 nautical miles) from the nearest PSD Class II modeled receptor. To ensure the modeled worst-case impact conditions include the worst-case project location, all impact modeling estimates were performed with the drilling vessel located at the northwest corner of the closest lease block to the shoreline and to the nearest PSD Class I area (Breton National Wildlife Refuge (NWR)).

The modeling locations of the associated support vessels (*i.e.*, crew boats and OSVs) for the *Developer* can also affect the modeled impacts. The modeled worst-case impact location for the crew boats and OSVs is 25 nautical miles from the main drilling vessel in the direction of the closest receptor (*i.e.*, toward the Breton NWR). This location was used for all impact assessment except PSD Class I area visibility. The mobile support vessels were modeled as 100 volume sources distributed along the 25 nautical mile path. The initial plume dimensions (i.e., sigma-y and sigma-z) were based on the width and height of a representative support vessel. The *Developer* drilling vessels require no support vessels during deployment, so there is no distinction between the maximum 1-hour and maximum 24-hour emission rates used for the Class I visibility assessment.

In addition to emission rates, the modeling analysis requires information regarding stack heights and other exit parameters that characterize exhaust flow from emission points. These release characteristics have an important influence on the results of the analysis. Exhaust stack parameters for the *Developer* drilling vessel, as well as the crew boats and OSVs, are provided in the September 2012 Outer Continental Shelf Title V and PSD Permit Application DeSoto Canyon Drilling Exploration Project and June 2013 Revised Section 6 - Air Quality Impact Assessment documents contained in the Administrative Record (see Section 9). Maximum short-term and long-term emission rates are provided in this document.

7.2.3 Meteorological Data

The three-year meteorological dataset (2001-2003) developed by the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) was used for the PSD Class II and Class I impact assessments. This 4-km VISTAS Domain 2 dataset was developed by the Federal Land Managers using the approved regulatory version of CALMET (Version 5.8, Level 070623). The dataset was developed using observations from 100 to 109 surface stations, 10 upper air stations, nine overwater stations and 92 to 103 precipitation stations, depending on the meteorological year. This sub-domain includes a 50 km buffer past the Breton Class I area, far enough east for receptors along western Florida, and far enough south to include a 100 km buffer around the drilling location to allow re-circulation of puffs.

7.2.4 Building Downwash

Building downwash accounts for the effect of nearby structures on the flow of emissions from their respective release structures. However, as noted above, building downwash effects were not included in the modeling as they will not significantly affect concentrations when the nearest receptors are located more than 100 km from the location of the emissions. Because of this, FLMs typically do not request downwash be included in long-range PSD Class I impact assessments.

7.2.5 Receptor Locations

The seaward boundaries and Air Quality Control Regions for Louisiana, Mississippi and Alabama extend for three nautical miles offshore and for nine nautical miles offshore Florida. For the Statoil Class II modeling analysis, discrete receptors were located 25 nautical miles from the seaward boundaries of Louisiana, Mississippi, Alabama, and Florida. The receptors were placed at 1-km intervals but controlling concentrations were resolved to 100-m, if needed. The location of these receptors is shown in Figure 7-1 as the dark/red line parallel to the shoreline. Because all of these receptors are over water, terrain elevations were assigned an elevation of 0 m (*i.e.,* sea level) for the Class II impact analysis: [Note: Class I receptors for the Breton Wilderness were obtained from the National Park Service website (http://www.nature.nps.gov/air/Maps/Receptors/index.cfm). These FLM-specified receptors include elevations that range from 0.021 to 0.375 m.]

7.2.6 Project Impact Assessment

This section presents the estimated ambient concentrations associated with the emissions from the proposed *Developer* exploration activities. If a pollutant's estimated impact exceeds an EPA SIL for that pollutant, the impacts of the facility must be included with the impacts of other increment-consuming sources to evaluate total increment consumption. Exceeding a SIL also requires that the evaluation of compliance with the applicable NAAQS take into account background concentrations and the contributions of other regional sources.

The SILs are screening values that have been used since 1980 to identify de minimis impacts. However, as discussed above, on January 22, 2013, the D.C, Circuit vacated the $PM_{2.5}$ SIL and SMC provisions adopted in the EPA's PSD Regulations (40 CFR 51.166 and 40 CFR 52.21). As discussed below, the EPA's review of Statoil's application is consistent with the D.C. Circuit's decision.

The proposed project emissions from the *Developer* drilling vessel, as well as the associated support vessels, were modeled for comparison to the SMC and SIL for NO_2, PM_{10}, and $PM_{2.5}$. The maximum modeled project concentrations at the discrete 25- nautical mile receptors were compared to the PSD Class II SILs for NO_2, PM10, and $PM_{2.5}$. Similarly, the maximum modeled pollutant concentrations at the discrete 25-nautical mile receptors were compared to the SMC for these pollutants.

The impact modeling results are provided and compared to the SIL and SMC in Table 7-1. Because all maximum predicted NO_2, PM_{10}, and $PM_{2.5}$ concentrations are less than the SIL, the project's estimated impacts are not considered to cause or contribute to a violation of the associated NAAQS or PSD increments. Furthermore, all maximum predicted concentrations are also much less than the SMC; therefore, no pre-construction ambient monitoring is required.

Table 7-1
Maximum Modeled PSD Class II Area Concentrations

Pollutant	Averaging Period	*Developer* Max. Concentration (ug/m^3)	Significant Impact Levels (ug/m^3)	Significant Monitoring Concentrations (ug/m^3)
NO_2 [a]	1-hour[b]	6.5	7.5	None
	Annual	0.042	1.0	14
$PM_{2.5}$	24-hr[b]	0.09	1.2[c]	vacated
	Annual	0.0015	0.3[c]	None
PM10	24-hr	0.107	5	10
	Annual	0.0017	1	None

[a] Annual NO_X was conservatively assumed to be 75 percent NO_2. One-hour NO_X modeled value provided is three year average of the maximum daily 1-hour NO_X concentration at each receptor with 80 percent NO_2 conversion.
[b] Maximum (100 percentile) values are provided not 98[th] percentile.
[c] The $PM_{2.5}$, SIL, and SMC were vacated in January 2013.

The vacatur and remand of the $PM_{2.5}$ SIL resulted in a need for additional demonstration that use of the SIL is appropriate to identify insignificant impacts. Similarly, the SMC were vacated so pre-construction ambient air quality monitoring is required. Applicants may submit existing ambient air quality data collected from existing monitoring networks in lieu of pre-construction monitoring if such data is demonstrated to be representative or conservative for the impact area.

Statoil reviewed the available $PM_{2.5}$ air quality monitoring data for the EGOM. Although there are no existing $PM_{2.5}$ measurements in the vicinity of Statoil's lease blocks, there are a number of shore-based monitors. Because of the scarcity of $PM_{2.5}$ sources in the EGOM and the project's large distance from land-based sources, the background ambient $PM_{2.5}$ concentration in the EGOM OCS are expected to be lower than any onshore concentrations. Therefore, the existing onshore ambient monitoring data will provide conservative background ambient $PM_{2.5}$ concentrations for the project location. The maximum $PM_{2.5}$ 24-hour and annual Design Values from the 18 existing shore-based monitors for the 2009-2011 period were 28 and 10.4 ug/m^3, respectively.

The PSD $PM_{2.5}$ 24-hour NAAQS is 35 ug/m^3 and the PSD Class II SIL is 1.2 ug/m^3. The annual $PM_{2.5}$ NAAQS is 12 ug/m^3 and the Class II SIL is 0.3 ug/m^3. The difference between the $PM_{2.5}$ NAAQS and the selected conservative ambient background concentrations are larger than the $PM_{2.5}$ Class II SILs. The fact that the maximum impacts from project emissions are substantially less than the SILs (*i.e.*, Table 7-1 Class II maximum project impacts are 7.5% of the 24-hour and 0.5% of the annual $PM_{2.5}$ SIL) provides further support for the use of the SILs in this application. Hence, it is reasonable to conclude that a proposed source with a $PM_{2.5}$ impact below the $PM_{2.5}$ SIL values will not cause or contribute to a violation of the $PM_{2.5}$ NAAQS.

In terms of the PSD Class I areas where compliance with the PSD increments are of concern, the SILs are used as a screening tool to assess whether a full cumulative Class I increment assessment is needed. The $PM_{2.5}$ increments became effective relatively recently (Major Source Baseline date of October 20, 2010; trigger date of October 20, 2011). Because of different meteorological conditions, PSD increment consuming emissions from outside the EGOM would not affect a Class I area at the same time as emissions originating from the EGOM. Therefore, given the conservative project emission rates and release location (*i.e.*, nearest possible distance to a Class I ambient receptor), the small number of other possible $PM_{2.5}$ increment consuming emission sources in the EGOM and onshore areas, and the unlikely combined simultaneous contributions from land-based and OCS $PM_{2.5}$ emission sources, the use of the $PM_{2.5}$ Class I SILs should not jeopardize PSD Class I increments.

7.2.7 Ozone

Both VOC and NO_X are precursors to ozone formation and the project's estimated VOC and NO_X emissions exceed the significant emission rate. Thus, assessment of the project's ozone impacts is required. The estimated project emissions are provided in Table 4-1. An adequate ozone formation model has not been developed for this type of sole source application. Hence, the EPA concurred that a qualitative or relative assessment could be performed.

To put the project's NO_X and VOC emissions in perspective, the applicant compared the proposed project emissions to Gulf of Mexico emissions reported in the 2008 Emissions Inventory from the Bureau of Safety and Environmental Enforcement (BSEE). This inventory indicates there are 3,027 point sources that emit either VOC or NO_X located in the Gulf of Mexico west of 87 degree 30 minute longitude. The 2008 Gulfwide Emission Inventory Study Report (latest inventory report of the Bureau of Energy Management, Regulation and Enforcement) provides estimates of total emissions of NO_X and VOC from all the sources in the Gulf of Mexico. Comparing the proposed project emissions with these estimates reveal project emissions are about 0.75% of total NO_X and 0.12% of total VOC Gulf of Mexico emissions.

For further comparison, Table 7-2 presents the statewide total NO_X emissions from the 2008 National Emissions Inventory (NEI) for the states around the Gulf of Mexico as summarized from information provided in the Technical Support Document for the EPA Federal Transportation Rule (EPA-HQ-OAR-2009-0491). This document shows that on-road sources contributed the most to the total NO_X emissions in the Gulf States. Estimated project emissions are very small when compared with the total NO_X emissions of nearly 4.0 million tons from the five Gulf States.

Table 7-2
State NO_X Emissions for Gulf States in the 2008 NEI

State	NO_X Emissions (TPY)
Alabama	421,467
Florida	895,436
Louisiana	548,439
Mississippi	278,745
Texas	1,827,200
Total	**3,971,287**

Another consideration is the distance from the closest Statoil lease location to the coastline. The nearest coastline is at the mouth of the Mississippi Delta more than 180 km from the nearest lease location. Therefore, emissions of NO_X and VOCs from the project need to travel more than 100 miles to reach the coastline to potentially contribute to on-shore ozone concentrations. In addition, the wind speeds direction in the eastern Gulf of Mexico changes frequently, so the project emissions will be distributed over a wide area. Based on the above information and considerations, project emissions are not expected to significantly impact ozone formation along and near the coastal areas of the Gulf of Mexico.

7.2.8 Additional Impact Assessments

An additional impacts analysis was performed in accordance with PSD requirements in 40 CFR § 52.21(o). The analysis evaluates the potential impacts that the emissions from the proposed exploration activities could have on growth, soils, vegetation, and visibility in the OCS impact area of concern.

7.2.8.1 Growth

The potential growth of industrial, commercial, and residential sources as a result of the proposed exploration activities is expected to be minimal. The current infrastructure that supports the well-developed oil and gas activities in the area just west of the proposed drilling activities is adequate to support the proposed drilling activities and no additional growth is expected.

7.2.8.2 Soil and Vegetation

The potential impacts of the proposed project on the soils and vegetation in the project's impact area must be considered. Assessment of impacts to vegetation having no significant commercial or recreational values is not required. Due to the location of the proposed exploration activities in the eastern Gulf of Mexico more than 150 km from any coastline and the modeled project impacts of less than significant levels, no significant impact from the proposed project to soils or vegetation is expected.

7.2.8.3 Visibility

The estimate of project impact on visibility in the project's impact area was assessed using the EPA plume impact screening model VISCREEN. The VISCREEN model estimates the potential visual impact of a plume caused by a proposed project's emissions. A VISCREEN Level I analysis was conducted to estimate if the emissions from the proposed exploration activities could result in an adverse impact on visibility at the closest visibility sensitive Class II area receptor. The project's particulate matter and NO_X emissions were provided as inputs, while the default values were used for background ozone, stability class, and wind speed (default background ozone concentration of 0.04 parts per million, and default stability and wind speed are 6 and 1 meter per second, respectively). VISCREEN conservatively evaluated whether a plume from the *Developer* drilling vessel, and associated support vessels, will produce a plume perceptible to an observer under worst-case meteorological conditions at a specific location. Several angles between the observer's line of sight and the sun's radiation (θ) are considered.

The application of VISCREEN is limited to distance less than or equal to 50 km. Therefore, to conservatively estimate the potential visual impact in the impact area that is more than 150 km from the drilling location, the much smaller 50 km distance was used in the VISCREEN analysis. Two criteria are assessed in the analysis, delta E and contrast. Delta E, also called plume perceptibility, refers to the color difference between the plume and background (*i.e.*, brightness, color hue, and color saturation). The default threshold or "critical" value for delta E is 2.0. Contrast, also referred to as green contrast value or Cp, represents the contrast of a plume against a background such as the sky or a terrain feature. Change in contrast is measured in terms of green color wavelength. The default threshold or "critical" value for contrast is 0.05.

Tables 7-3 provides the results of the VISCREEN modeling for the *Developer* drilling vessel. This table shows that the default threshold for Delta E and contrast (Cp) were not exceeded for sky or terrain backgrounds by the drilling vessel at 50 km distance. Therefore, the proposed *Developer* exploration activities are not expected to impair the local visibility at the closest areas of concern, 25 nautical miles from each state's seaward boundary.

Table 7-3
VISCREEN Level 1 *Developer* Results

Background	Θ	Distance	Delta E	Contrast

		(Source-Observer)	Critical	Plume	Critical	Plume
Sky	10	50 km	2.00	1.254	0.05	-0.007
Sky	140	50 km	2.00	0.387	0.05	-0.009
Terrain	10	50 km	2.00	0.079	0.05	0.001
Terrain	140	50 km	2.00	0.023	0.05	0.001

7.3 PSD Class I Areas Analyses

The PSD Class I areas nearest to the project location are Breton National Wildlife Refuge (175 km), Bradwell Bay Wilderness Area (307 km), Saint Marks Wilderness Area (313 km), and Chassahowitzka Wilderness Area (641 km). The FLM for Breton, Chassahowitzka, and Saint Marks Wilderness Areas is the Fish & Wildlife Service (FWS). The FLM for the Bradwell Bay Wilderness Area is the National Forest Service. Discussions with the FWS concerning the proposed project resulted in a request for an Air Quality Related Values (AQRV) assessment for Breton NWR, the nearest PSD Class I area. Visibility and nitrogen and sulfate deposition are the AQRV of concern at the Breton National Wildlife Refuge. In addition to AQRV of concern to the FLM, the EPA requires the assessment of PSD Class I increments. The PSD increment at the Breton NWR was assessed using the same model and modeling procedures as used for the PSD Class II impact assessment.

7.3.1 Air Quality Model Selection

The EPA-preferred model for long-range transport assessments, CALPUFF Version 5.8, was used to evaluate potential AQRV and PSD increment impacts at Breton NWR. This model is also recommended by the FLM for Breton NWR.

7.3.2 Modeling Procedures

The modeling procedures used for the Class I area impact analyses followed the recommendations of the Interagency Workgroup on Air Quality Modeling and the FLM Air Quality Related Values Workgroup (FLAG), outlined in the FLAG Phase I Report - Revised (2010). The selected options for the CALPUFF modeling system followed the procedures and defaults approved by the FLM and/or the EPA.
The CALPUFF-estimated hourly PM_{10}, $PM_{2.5}$, and NO_2 concentrations were averaged for the annual and 24-hour periods. Visibility extinction coefficients and total deposition fluxes were calculated for 24-hour and annual averages, respectively. Comparisons to the regulatory standards and/or FLM target values were based on the maximum modeled values from the modeled three-year meteorological dataset.

The CALPUFF chemistry transformations depend on the ambient ammonia and ozone concentrations. Because of the low ammonia background concentration expected over the Gulf of Mexico, the FLM requested value of 3 ppb was used. The ozone background concentrations for the 2001-2003 modeled years were those included with the meteorological dataset. A conservative background value of 65 ppb was used for any missing values.

The Class I area modeling assessment used the maximum short-term (i.e., 24-hour emission rate) and long-term emission scenarios for the *Developer* drilling vessel (see Section 7.2.2). The operational scenarios that produce the maximum hourly emission for the vessels were used to obtain the maximum 24-hour impact values.

To provide the worst-case impact condition the drilling vessel was located at their closest location – the NW corner of the lease block nearest Breton. For all impact analyses except PSD Class I area visibility, crew boats and OSVs were modeled as point sources located 25 nautical miles from the drilling vessel in the direction of the nearest shore receptor and Breton NWR. For the PSD Class I visibility assessment, the mobile support vessels were modeled as 100 volume sources distributed along the 25 nautical mile path. The initial plume dimensions (i.e., sigma-y and sigma-z) were based on the width and height of a representative support vessel.

7.3.4 Meteorological Data

The three-year meteorological dataset (2001-2003) developed by the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) was used for the PSD Class I impact assessment. This dataset, the same as used for the PSD Class II impact assessment, covers the Gulf of Mexico region of interest. This analysis used a 4-km grid size to better resolve the impacts.

7.3.5 Modeling Results

The maximum Class I area estimated impacts from the proposed exploratory drilling emissions are provided in Table 7-4. The accepted PSD Class I annual SIL is also provided in this table. The maximum modeled concentrations associated with the proposed project emissions for the *Developer* drilling vessel are much less than the SIL. Therefore, the project is considered to have no significant impact on the PSD Class I increments.

Table 7-4
Maximum Modeled Class 1 Concentrations

Criteria Pollutant	***Averaging Period***	***Developer Max. Concentration*** (ug/m^3)	***EPA SIL*** (ug/m^3)
NO_2[a]	Annual	0.018	0.1
PM2.5[b]	24-hr	0.047	0.07[c]
	Annual	0.0007	0.06[c]
PM10	24-hr	0.052	0.3
	Annual	0.0008	0.2

[a] NO_X was assumed to be 75 percent converted to NO_2.
[b] 100 percent (maximum) values are provided using direct $PM_{2.5}$ emissions only.
[c] The Class I $PM_{2.5}$ SIL was vacated in January2013.

Given the conservative emission rates and release location (i.e., nearest possible distance to Class I ambient receptor), and small number of other possible increment consuming $PM_{2.5}$ emission sources in the eastern Gulf of Mexico, the use of the $PM_{2.5}$ SIL should not jeopardize PSD Class I increment at this area. The fact that the maximum modeled project emissions are substantially lower than the SIL (*i.e.*, the Table 7-4 maximum project impacts are 67.1% of the 24-hour and 1.2% of the annual $PM_{2.5}$ SIL) adds support for the use of the SIL as an indicator of insignificant project impacts in this application.

The CALPUFF estimates of deposition of acid-forming compounds from the project's emissions are provided in Table 7-5. This table also contains the FLM accepted Deposition Analysis Thresholds (DAT) established for areas east of the Mississippi. The DAT is defined as the additional amount of nitrogen or sulfur deposition within a PSD Class I area below which estimated project impacts are considered negligible [Federal Land Manager's Air Quality Related Values Workgroup, Phase I Report – Revised June 2008]. The estimated project deposition rates are much less than the DAT. Therefore, the project associated Class I area deposition should be negligible.

Table 7-5
Estimated Class I Area Deposition Fluxes (kg/ha/yr)

Class I Area	***Developer***
	Nitrogen Deposition
Breton NWR	0.0014
Deposition Analysis Threshold	0.010

The visibility concern at Breton NWR is regional haze. The project's contribution to regional haze is addressed as the 24-hour change in extinction. The FLM considers a five percent change in extinction to be just perceptible. The FLM accepted procedures known as Method 8 was used. Method 8 employs the IMPROVE extinction equation using monthly relative humidity adjustment factors, annual background aerosol concentrations, and 98th percentile modeled values at each receptor to provide estimates of the change in extinction associated with project emissions.

Visibility extinction coefficients were calculated for 24-hour averages. Comparison with FLM-recommended criteria for regional visibility impacts is shown by calculating the change in 24-hour extinction for each Class I receptor. The CALPUFF modeling system was used to predict both the extinction coefficient attributable to emissions from the project as well as the background extinction coefficients for that day's meteorology.

The Method 8 estimated project associated changes in visibility extinction for the *Developer* vessel resulted in a number of days with more than five percent change in extinction. The *Developer* assessment resulted in 19 days over a three year period from 2001 through 2003 exceeding five percent change in extinction with a maximum of 18.95 percent. Fourteen of the 19 days had changes of less than 10 percent. Table 7-6 provides a summary of the results of the Method 8 modeling analysis. This table reveals that the three year average Method 8 98th percentile value for the drilling vessel is less than the five percent change in extinction that the FLM considers to be the perceptible level.

Table 7-6
Summary of Method 8
Maximum Estimated Change in Extinction for Breton Wilderness

Criteria	***Developer* (%)**
Highest Value	18.95
Number Days > 5% Change	19
Number Days >10% Change	5
98th Percentile Change 2001	5.03
98th Percentile Change 2002	4.32
98th Percentile Change 2003	4.73
98th Percentile Change 3 year average	4.69

The estimated impacts of the proposed project's emissions on the nearest PSD Class I area shows visibility impacts for the *Developer* just greater than the FLM perceptibility level. The drilling vessel's deposition levels are less than the FLM's DAT values. The Breton NWR FLM reviewed this PSD Class I area impact assessment and indicated that because of the conservative assumptions contained in the emission estimates and analyses, and the temporary nature of the activity, they expected no significant project-related impacts.

8.0 Additional Requirements

8.1 Endangered Species Act and Essential Fish Habitat of Magnuson-Stevens Act

Section 7(a)(2) of the Endangered Species Act (ESA) requires federal agencies, in consultation with the National Oceanic and Atmospheric Administration (NOAA) Fisheries Service and/or the U.S. Fish and Wildlife Service (collectively, "the Services"), to ensure that any action authorized, funded, or carried out by the agency is not likely to jeopardize the continued existence of a species listed as threatened or endangered, or result in the destruction or adverse modification of designated critical habitat of such species. *See* 16 U.S.C. §1536(a)(2); *see also* 50 CFR §§ 402.13 and 402.14. The federal agency is also required to confer with the Services on any action which is likely to jeopardize the continued existence of a species proposed for listing as threatened or endangered or which will result in the destruction or adverse modification of critical habitat proposed to be designated for such species. *See* 16 U.S.C. § 1536(a)(4); *see also* 50 CFR §§ 402.10. Further, the ESA regulations provide that where more than one federal agency is involved in an action, the consultation requirements may be fulfilled by a designated lead agency on behalf of itself and the other involved agencies. *See* 50 CFR §§ 402.07.

Section 305(b)(2) of the Magnuson-Stevens Fishery Conservation and Management Act (MSA) requires federal agencies to consult with NOAA with respect to any action authorized, funded, or undertaken by the agency that may adversely affect any essential fish habitat identified under the MSA. The Bureau of Ocean Energy Management (BOEM) of the DOI is the lead federal agency for authorizing oil and gas exploration activities on the OCS. BOEM serves as the Lead Agency for ESA section 7 and MSA compliance for Statoil's exploration activities. In accordance with section 7 of the ESA, BOEM consults prior to a lease sale with NOAA Fisheries and FWS to ensure that a sale proposal will not cause any protected species to be jeopardized by oil and gas activities on a lease. In addition, BOEM requests annual concurrence from the Services to ensure current activities remain consistent with the terms and conditions of the Biological Opinion issued for the lease sale activities.

Since the BOEM consultations address the same exploratory drilling activities authorized by the air permit that the EPA is proposing to revise, the EPA relied in part on those conclusions for our preliminary determination. In addition, NOAA Fisheries considered the scope of the proposed action and did not identify any routes of effects for air quality. Based upon the best available data and technical assistance from the Services, the EPA determined that the issuance of this OCS permit to Statoil for exploratory drilling is not likely to cause any adverse effects on listed species and essential fish habitats beyond those already identified, considered and addressed in the prior consultations. The proposed OCS permit includes a condition requiring Statoil to comply with all other applicable federal regulations, which includes the results of any current and future biological opinions. This determination remains unchanged from the original permit action.

8.2 National Historic Preservation Act

Section 106 of the National Historic Preservation Act requires federal agencies to take into account the effects of their undertakings on historic properties. Section 106 requires the lead agency official to ensure that any federally funded, permitted, or licensed undertaking will have no effect on historic properties that are on or may be eligible for the National Register of Historic Places. The BOEM is the lead agency permitting Statoil's activity in the Gulf of Mexico. BOEM typically conducts section 106 consultation at the pre-lease stage by prior agreement with the Advisory Counsel for Historic Preservation rather than at the individual post-lease permit level. In order to reach a Finding of No Significant Impact, mitigation is carried out at the post-lease plan level by requiring remote sensing survey of the seafloor in areas considered to have a high probability for archaeological resources. Any cultural resources discovered during that inspection are required by regulation to be reported to BOEM with 72 hours. No significant archaeological properties are anticipated in this location, but should anything be discovered there as a result of the operator's investigations, BOEM would enter into consultation with the State Historic Preservation Office and the Advisory Counsel for Historic Preservation.

8.3 Executive Order 12898 – Environmental Justice

Executive Order 12898, entitled "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," directs federal agencies, including the EPA, to the extent practicable and permitted by law, to identify and address, as appropriate, disproportionately high and adverse human health or environmental effects of regulatory programs, policies, and activities on minority populations or low-income populations. *See* Executive Order 12898, 59 Fed. Reg. 7629 (February 11, 1994). Consistent with Executive Order 12898 and the EPA's environmental justice policy (OEJ 7/24/09), in making decisions regarding permits, such as OCS permits, the EPA gives appropriate consideration to environmental justice issues on a case-by-case basis, focusing on whether its action would have disproportionately high and adverse human health or environmental effects on minority or low-income populations.

The EPA has concluded that this proposed OCS air permit revision for Statoil's exploratory drilling operation on the Gulf of Mexico would not have a disproportionately high adverse human health or environmental effects on minority or low-income populations. The drilling area is located approximately 160 miles southeast of the mouth of the Mississippi River and 200 miles southwest of Panama City, Florida in the Gulf of Mexico. The project is located more than 150 miles offshore in ultra-deepwater and the EPA is not aware of any minority or low-income population that may frequently use the area for recreational or commercial reasons. In addition, since the project is located well away from land, the project's emissions impacts will be dispersed over a wide area with no elevated concentration levels affecting any onshore populated area. *See* Section 7.0 of this document pertaining to air quality impact. This determination remains unchanged from the original permit action.

9.0 Public Participation

9.1 Opportunity for Public Comment

While neither the OCS nor PSD regulations address the administrative procedures for permit revisions, given that the revisions change the BACT emission limits previously offered for public comment and include new BACT limits and work practice standards, the EPA is following the procedures of 40 CFR part 124 and 40 CFR part 71 in processing this permit revision. As required by these provisions, the EPA is seeking public comment on the revisions incorporated into the Statoil OCS air permit OCS-EPA-R4012-M1.

Any interested person may submit written comments on the draft revisions to the permit during the public comment period. If you believe that any revision to the permit is inappropriate, you must raise all reasonably ascertainable issues and submit all reasonably available arguments supporting your position by the end of the comment period. Any documents supporting your comments must be included in full and may not be incorporated by reference unless they are already part of the administrative record for this permit or consist of state or federal statutes or regulations, EPA documents of general applicability, or other generally available referenced materials.

Comments should focus on the proposed revisions to the air quality permit, EPA's analysis of the modification, and the revised air quality impacts of the project. If you have comments regarding non-air quality impacts, leasing, drilling safety, discharge, or other similar issues not subject to this public comment period, you should submit them during the leasing and plan approval proceedings of the BOEM, which is the lead agency for offshore drilling.

All timely comments related to the proposed action will be considered in making the final decision and will be included in the administrative record and responded to by the EPA. The EPA may summarize the comments and group similar comments together in our response instead of responding to each individual commenter.

All comments on the draft permit revisions must be received by email at **R4OCS permits@epa.gov**, submitted electronically via www.regulations.gov (docket # EPA-R04-OAR-2014-0510), or **postmarked by August 8, 2014**. Comments sent by mail should be addressed to: USEPA Region 4, Air Permits Section APTMD, 61 Forsyth Street, SW, Atlanta, GA 30303; Attn: Rosa Yarbrough. An extension of the 30-day comment period may be granted if the request for an extension is filed within the 30-day comment period and it adequately demonstrates why additional time is required to prepare comments. All comments will be included in the public docket without change and will be made available to the public, including any personal information provided, unless the comment includes Confidential Business Information or other information in which disclosure is restricted by statute. Information that you consider Confidential Business Information or otherwise protected must be clearly identified as such and should not be submitted through e-mail. If you send e-mail directly to the EPA, your email address will be captured automatically and included as part of the public comment. Please note that an e-mail or postal address must be provided with your comments if you wish to receive direct notification of the EPA's final decision regarding the permit and the EPA's response to comments submitted during the public comment period.

For general questions on the draft permit, contact: Ms. Lori Shepherd at 404-562-8435 or shepherd.lorinda@epa.gov.

9.2 Public Hearing

The EPA will hold a public hearing if the Agency determines that there is a significant degree of public interest in the draft permit revisions. Public Hearing requests must be in writing and received by EPA by **July 31, 2014.** Requests should be sent by email to **R4OCSpermits@epa.gov** or by mail addressed to: USEPA Region 4, Air Permits Section, 61 Forsyth Street, SW, Atlanta, GA 30303. Requests for a public hearing must state the nature of the issues proposed to be raised in the hearing. If a public hearing is held, you may submit oral and/or written comments on the draft permit at the hearing. You do not need to attend the public hearing to submit written comments. If EPA determines that there is a significant degree of public interest in the draft permit revisions, EPA will hold a public hearing on August 14, 2014, at:

Bay County Public Library
Northwest Regional Library System
898 W 11th Street
Panama City, FL 32412-0625
(850) 522-2119

If a public hearing is held, the public comment period will automatically be extended to the close of the public hearing. If no timely request for a public hearing is received, or if EPA determines that there is not a significant degree of public interest, a hearing will not be held. Such an announcement will be posted on EPA's website at:

http://www.epa.gov/region4/air/permits/ocspermits/ocspermits.html,

or, you may call the EPA at 404-562-9643 to verify if the public hearing will be held.

9.3 Administrative Record

The administrative record contains the application, supplemental information submitted by Statoil, correspondence (including e-mails) clarifying various aspects of Statoil's application, other material used in the EPA's decision and rationale process, and correspondence with other agencies. The administrative record and draft permit are available on www.regulations.gov (docket# EPA-R04-OAR-2014-0510) and through the EPA's website at:

http://www.epa.gov/region4/air/permits/ocspermits/ocspermits.html.

These web sites can be accessed through free internet services available at local libraries.
The draft permit and the administrative record are also available for public review at the EPA Region 4 office at the address listed below. Please call in advance for available viewing times.

EPA Region 4 Office
61 Forsyth Street, SW
Atlanta, GA 30303
Phone: (404) 562-9043

To request a copy of the draft permit, preliminary determination or notice of the final permit action, please contact: Ms. Rosa Yarbrough, Permit Support Specialist at: 404-562-9643, or yarbrough.rosa@epa.gov.

9.4 Final Determination

The EPA will make a decision to issue a final revised permit, or to deny the application for the permit modification, after the Agency has considered all timely comments on the proposed determination.

Notice of the final decision shall be sent to each person who has submitted written comments or requested notice of the final permit decision, provided the EPA has adequate contact information.