Air Quality Control, Reporting, and Compliance

Initial Regulatory Impact Analysis

RIN: 1010-AD82

NOTICE OF PROPOSED RULEMAKING

DEPARTMENT OF THE INTERIOR

Bureau of Ocean Energy Management

(30 CFR Part 550: Subparts A, B, C & J)

March 3, 2016

Contents

EXECUTIVE SUMMARY

This document describes the regulatory impact analysis (RIA) conducted for the proposed rule, RIN 1010-AD82, Air Quality Control, Reporting, and Compliance. The Bureau of Ocean Energy Management's (BOEM) proposed changes for the Outer Continental Shelf (OCS) air emissions requirements primarily apply to attributed plan emissions, measurement periods, monitoring and to those situations where air dispersion or photochemical modeling, or emissions reduction measures will be required.

The compliance costs for this rulemaking primarily relate to air dispersion and photochemical modeling, air pollutant emissions monitoring, air quality monitoring and the implementation of emission reduction measures (including the use of emissions credits). The remaining compliance costs are for additional paperwork burden hours identified in the Paperwork Reduction Act (PRA) for operators submitting Exploration Plans (EPs) and Development Operations Coordination Documents (DOCDs) or Development and Production Plans (DPP) pipeline Rights-of-Way (ROW), Right-of-Use and Easement (RUE) and lease term pipeline applications. BOEM estimates the industry compliance costs for activities in the first year will be $23 million, the peak year (2020) $49 million and $290 million over 10 years discounted at 3 percent. The government staffing costs are estimated to be about $1.6 million per year and $12 million over 10 years discounted at 3 percent. BOEM estimates the total first year compliance cost for both the regulated industry and the government is $23.6 million, $51 million for the peak year and over 10 years is $302 million discounted at 3 percent.

The primary benefit of this rule is to ensure that offshore facilities and operations are in compliance with the air quality objectives and requirements of the OCSLA. Other benefits include the anticipated reduction of the level of pollutants due to proposed emission reduction measures or emissions offsets.

Based on historical information submitted to BOEM in EPs, DOCDs and DPPs, the pollutant most likely to require reductions under this proposed rule is NO_x (including nitric oxide and nitrogen dioxide). Lessee/operator submitted plans exceeding the existing emission threshold, or for which air dispersion modeling indicates the significant impact levels (SILs) exceedance in nonattainment areas for 1-hour NOx, will require emissions reduction measures or procurement of emissions credits on select facilities to bring certain plans into air quality compliance. Emission reductions may be required on the large Category 3 marine engines and can be achieved through several different methods including selective catalytic reduction (SCR) technology, Tier-3 marine engines with SCR capability, operational controls or emission credits. SCR is the most effective and expensive best available control technology (BACT). Based on a review of Gulf of Mexico (GOM) DOCDs and EPs there are likely several development profiles each year that would require SCR BACT or Tier-3 marine engines. These projects are likely to be deepwater development projects employing at least two mobile offshore drilling units (MODUs) less than 100 miles from shore or smaller shelf development projects close to the federal/state submerged lands boundary. The greatest compliance cost and NOx reduction benefits are expected for deepwater projects, especially in the Mississippi Canyon area. The quantifiable benefits are estimated to range from $8 million to $43 million per year and are attributed to the NOx reductions due to emission reduction measures or emissions credits on those few projects that are expected to require emission reductions. The net quantified benefits for this proposed rule are estimated to be positive in the first three years and negative in all subsequent years of the 10-year window of this analysis. Table 1 summarizes the estimated annual net benefits.

Table 1. Estimated Annualized Rulemaking Net Benefits

Millions$ Years -->	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Estimated Industry Compliance Costs	$22.9	$29.9	$35.9	$49.4	$45.1	$36.6	$31.5	$31.7	$27.7	$28.4
Estimated Benefit (NOx Reductions)	$26.5	$35.3	$43.1	$43.1	$34.3	$18.6	$8.8	$7.8	$0.0	$0.0
Estimated Net Benefit	$3.5	$5.4	$7.2	-$6.3	-$10.8	-$18.0	-$22.7	-$23.9	-$27.7	-$28.4

Co-benefits, such as emissions reductions of other pollutant emissions associated with the proposed controls for NO_x, have not been evaluated or quantified in this analysis.

The proposed air quality regulations would strengthen the requirements for identifying, modeling, measuring and tracking the emissions of air pollutants. The improved air emissions information will better ensure BOEM only approves plans that meet the requirements of the Outer Continental Shelf Lands Act (OCSLA) (43 U.S.C. §§ 1331 et seq., Pub. L. 83-212, as amended). Coastal states and other stakeholders can thereby be more confident regarding the expected onshore air quality impacts from OCS oil and gas exploration and development. The additional monitoring information required for certain plans will also permit the Bureau of Safety and Environmental Enforcement (BSEE) to better assess the air quality compliance for OCS operations on a plan-by-plan basis.

The Office of Management and Budget (OMB) has determined that this rule is significant because it will potentially raise novel legal or policy issues. The novel legal and policy issues are the change in attributed emissions for plans as well as the relocation of the compliance boundary from the shoreline to the offshore submerged lands (state seaward) boundary used for determining exemptions from more detailed air quality analysis and/or modeled compliance with NAAQS. This rule formalizes the methodology for attributed emissions. The 25-mile radius traditionally used by BOEM will no longer apply; the projected emissions calculations consist of all emissions supporting a plan's activity, including in certain cases support emissions from aircraft and onshore facilities.

The most important benefit of the enhanced regulations is that these regulations will ensure compliance with the statutory mandates of OCSLA, which BOEM believes can be best achieved by amending BOEM's more than 35 year-old current regulations.

BOEM also believes that the rule could result in the reduction of VOCs, SOx, CO, and PM emissions, which have not been quantified, if operational controls are required as a condition of BOEM plan approval that would not otherwise be employed by operators. The qualitative benefits for the proposed regulatory changes include improved uniformity of regulations for all areas within DOI air quality jurisdiction. These changes link to EPA regulations and provide predictability and consistency for operators. Further, with the proposed changes to the regulations, BOEM will have one set of requirements, appropriate to both regions where BOEM has authority, which will be more effective and increase lessee compliance. The proposed regulatory changes will also provide BOEM and affected states improved information on the expected onshore air quality impacts of OCS exploration and development.

The quantified benefits are derived from anticipated NO_x reductions. Reducing NO_x yields health benefits both by reducing the harmful effects of NO_x[1] itself but also by reducing the rates of particulate matter and ozone formation. When fuel is combusted, some nitrogen (N_2) and oxygen (O_2) combine and form compounds like nitrogen dioxide (NO_2) and nitric oxide (NO). Once released into the atmosphere, nitrogen oxides react in the presence of sunlight with volatile organic chemicals to form ozone, the main ingredient in smog. NO_x also contributes to the creation of particulate matter and acid rain. A reduction in OCS air pollutants including NO_x reduces the risk of premature mortality in the U.S. population.

In addition, the proposed rule would eliminate the mandate to use BACT as an emissions control mechanism and would allow lessees and operators to utilize offsets whenever they are less expensive. This unquantified benefit would directly reduce the compliance costs of this rule, as compared to the current regulations, for any lessee or operator required to implement ERM.

INTRODUCTION AND BACKGROUND

The OCSLA authorizes the Secretary, Department of the Interior (Secretary) to prescribe and amend regulations as necessary to manage the orderly leasing, exploration, development, and production of mineral resources on the OCS. Specifically, OCSLA Sec. 5(a)(8) (43 U.S.C. §1334(a)(8)) requires the Secretary to prescribe regulations "for compliance with the National Ambient Air Quality Standards pursuant to the Clean Air Act (CAA) (42 U.S.C. §§7401 et seq., Pub. L. 88-206, as amended), to the extent that activities authorized under OCSLA significantly affect the air quality of any State." These proposed regulations would be codified at 30 CFR Part 550 subpart B "Plans and Information," subpart C "Pollution Prevention and Control." The proposed rule would also amend subpart J to add "Air quality requirements for pipeline right-of-way holders." The current regulations relative to the Air Quality Regulatory Program (AQRP) under subpart C have been fundamentally unchanged since their original promulgation in 1980, when they were applicable to all U.S. OCS planning areas, including Alaska. For that reason, this proposed rule represents the first substantial revision in the air quality regulations in over 35 years.

In 1990, with the passage of the CAA Amendments (Pub. L. 101-549), a revision to Section 328(a) & (b) (42 U.S.C. §7627(a) & (b)) of the CAA superseded OCSLA Sec. 5(a)(8), and redefined the Secretary's jurisdiction to regulate emission sources on the OCS. The revision limited the Secretary's jurisdiction to only those OCS areas westward of longitude 87 degrees and 30 minutes (central and western GOM), where compliance management responsibilities rest

[1] In addition to reductions in the rate of ozone formation resulting from NOx emissions reductions, there could also be reductions in the rate of ozone formation by unquantified reductions in VOCs. In addition, there could be additional reductions in the rate of PM formation that are due to unquantified reductions in non-NOx PM precursors.

with the BOEM Gulf of Mexico Region (GOMR). The 1990 CAA revision of Section 328(a) & (b) placed all other U.S. OCS planning areas, including Alaska, under the authority and jurisdiction of the U.S. Environmental Protection Agency (USEPA).

Congress revised Sections 328(a) and (b) of the 1990 CAA and restored jurisdictional responsibility to the Secretary for a portion of Alaska OCS with enactment of the "Consolidated Appropriations Act, 2012" (Pub. L. 112-74) on December 23, 2011. Specifically, the revision restored to the Secretary jurisdiction for the OCS planning areas adjacent to the Alaska North Slope Borough, which includes the Beaufort Sea OCS and the Chukchi Sea OCS Planning Areas (Arctic OCS), and a small portion of the Hope Basin OCS Planning Area. Air quality compliance management responsibilities for BOEM's Arctic jurisdiction rest with the BOEM Alaska Regional Office (AOCSR).

The proposed rule would amend the current regulations to respond to changes in environmental science and technology as well as advances in petroleum geology, exploration, drilling, and production practices. BOEM proposes to revise and update portions of the existing subparts A, B, C and J of 30 CFR Part 550 to update the OCS air emissions regulations for implementation by the GOMR and support the needs for the restored jurisdiction of AOCSR. The regulations proposed for revision relate to air emissions data required for proposed OCS exploration, development, ROWs and RUEs. The proposed rule incorporates by reference the appropriate updated national ambient air quality standards (NAAQS) established by the USEPA, and provides clarification of the compliance process.

Compliance with the standards relates to the submission of certain planning documents by the operator. These documents are multipurpose and cover many topics in addition to the AQRP. Plans also include specific information needed for the AQRP:

> An **Exploration Plan (EP)** describes all exploration activities planned by an operator for a specific lease(s), the timing of these activities, information concerning drilling vessels, the location of each well, and an analysis of both offshore and onshore impacts that may occur as a result of the plan's implementation. Emissions from or associated with an EP will usually be considered emissions from a short-term facility.
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> A **Development Operations Coordination Document (DOCD)** in the GOM and a **Development and Production Plan (DPP)** in Alaska is a plan that describes development and production activities proposed by an operator for a lease or group of leases. The description includes the timing of these activities, information concerning drilling vessels, the location of each proposed well or production platform or other structure, and an analysis of both offshore and onshore impacts that may occur as a result of the plan's implementation. Emissions from or associated with a DOCD or DPP will usually be considered emissions from a long-term facility.
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> **Pipeline Rights-of-Way (ROW) and Lease Term Pipeline applications** describe information relevant to pipeline designs prior to approving an application to ensure that the pipeline, as constructed, will provide for safe transportation of minerals through the submerged lands of the OCS. BSEE reviews proposed pipeline routes to ensure that the

pipelines would not conflict with any state requirements or unduly interfere with other OCS activities; BOEM reviews the applicable air emissions information to ensure compliance with the regulations.

Right-of-Use and Easement (RUE) is a platform, artificial island, installation and other device on submerged lands that is not on an OCS lease held by the RUE holder. BOEM reviews applicable air emissions information to ensure compliance with the regulations.

The first step in the BOEM AQRP is the exemption threshold analysis. BOEM determines, based on exploration or development plan proposed equipment and activity data provided by the lessee, whether or not any given plan (EP, DPP or DOCD) will generate emissions for the NAAQS pollutants above a distance-based exemption threshold. The plan's criteria pollutant emissions are calculated with standard emission factors in an Excel spreadsheet, and the default assumption is that all equipment will be operated at capacity for the duration of activity for a facility or associated vessels. The application of an exemption threshold determines whether air quality impacts would be *de minimus* and, therefore, not require further BOEM review. A plan whose emissions of all criteria and precursor pollutants is below the applicable exemption thresholds would be defined in the proposed rule as a plan that has no potential to significantly affect onshore air quality (and exempt from further review). If the projected emissions are above the exemption threshold, further analysis would be required. A plan whose emissions are above any applicable exemption threshold(s) would be defined as a plan that has the potential to significantly affect onshore air quality (and is, therefore, referred to as a non-exempt plan).

Rarely does a facility or vessel operate continuously at maximum levels and an operator may opt to use alternative emissions rates or activity levels if the operator agrees to provide verification and compliance data BOEM/BSEE. Use of any alternative factors may result in an approved plan being required to provide BOEM with data verifying emission rates, actual activity levels or fuel usage per proposed § 550.312(b). Verification of alternative emission rates may require a periodic stack test(s) measuring actual emission rates. BOEM may consider other plan mitigations for an exploration or development plan to ensure emissions are below the exemption formula threshold.

BOEM can approve EPs, DOCDs, and DPPs with facilities' whose air pollutant impacts are below the SILs (as determined by either the exemption formulas or modeling in cases where the emissions for a particular pollutant are above the exemption formula threshold) at the point in the state (including above state submerged lands) where the impact is the highest. In certain cases under the proposed rule BOEM may approve a plan with emissions above the SIL. The SIL is a measure of whether a source may cause or contribute to violation of the NAAQS. BOEM is conducting environmental studies, in both the GOM and Alaska OCS, to determine if the exemption formulas based on distance from the shoreline should be revised to be protective of the current NAAQS which have been promulgated since the last revision of the OCSLA air regulations. Air pollutants for which more recent NAAQS have been promulgated include 1-hr NO_2, 1-hr, SO_2, 24-hr PM_{10}, 24-hr $PM_{2.5}$ and annual $PM_{2.5}$ (where PM_{10} and $PM_{2.5}$ refer to particulate matter having a nominal aerodynamic diameter of 10 and 2.5 microns or less respectively). The USEPA also recently strengthened the 8-hour NAAQS for ground-level ozone to 70 ppb.

If a proposed plan would cause emissions of criteria or precursor air pollutants in excess of the applicable emissions threshold, the proposed plan would be required to include a detailed air quality analysis. If a proposed plan would not cause emissions of criteria or precursor air pollutants in excess of the formula thresholds, the plan would not be required to include a detailed air quality analysis. BOEM refers to plans that are not required to do a detailed air quality analysis as "exempt." In the event one or more criteria or precursor pollutants would exceed the applicable threshold, the operator would be required to proceed to the second step in the BOEM AQRP -- the dispersion modeling analysis. NO_x is the criteria pollutant most likely to exceed the exemption threshold; plan exceedance for NO_x also requires photochemical modeling for $PM_{2.5}$ and ozone when an approved photochemical model is available and BOEM has the results of the regional air quality studies (est. 2020). If the modeling shows that SILs, or the ambient air increment (AAI) or NAAQS would be exceeded for a state, then the applicant would be required to propose emission reduction measures. The nature and extent of the controls required for any facility depends on whether the state pollution impacts occur in an attainment or nonattainment area.

Under the proposed rule, the type of emissions reduction measures or BACT that would be required depend on whether the SIL exceedance is for an attainment area or non-attainment area of a particular state/local air quality jurisdiction. For long-term (non-temporary) facilities, the lessee or operator would be required perform additional modeling to determine if the controls will reduce onshore concentration increases below levels prescribed by EPA's PSD increments (also known as Ambient Air Increments – AAI). If emissions of a criteria pollutant still exceed these increments after modeling, emissions reduction measures or BACT would be would be required on the facility as a condition of approval for the exploration or development plan.

Proposed § 550.307(b)(1)(vi) would require modeling to demonstrate compliance with the NAAQS and, if necessary, the application of additional emission reduction measures to ensure NAAQS compliance. For a short term facility exceeding the SILs, emission reduction measures in the form of operational controls must be applied, but no additional modeling would be required, unless BOEM has reason to believe that the projected emissions will cause a NAAQS violation, (in which case the Regional Supervisor may require additional data, analysis or modeling to demonstrate compliance with the NAAQS per § 550.306(d)). Additional changes in this proposed rulemaking are described in the next section.

NEED FOR FEDERAL REGULATORY ACTION

The proposed Federal action would ultimately amend the existing regulations prescribed by the Secretary under subparts A, B, C and J of 30 CFR Part 550. These regulations inform lessees of the air emissions information and analysis BOEM requires when submitting a proposed EP, DPP, DOCD, pipeline rights-of-way (ROW), right-of-use and easement (RUE), or lease term pipeline application. Authority to amend the existing regulations is found under OCSLA Sec. 5(a), and the jurisdictional boundaries for application of the amendments is given under CAA Sec. 328(b).

The need is to ensure compliance with the NAAQS to the extent that activities BOEM authorizes significantly impact the air quality of any State. These amendments are necessary to establish up-to-date requirements with respect to air quality standards and criteria, preparation of projected emissions, air dispersion modeling, to monitor emissions, and control and offset emission sources. In addition, the purpose of the amendments is to ensure the consistent, efficient, and informed management of the OCSLA provision for air pollution prevention and control by the various BOEM regional offices.

There have been no substantive changes to the air quality rules and regulations established under OCSLA since their promulgation in 1980. During the ensuing 35 years, the USEPA has updated the CAA air regulations, but the existing OCSLA regulations were not rewritten nor commensurately updated to specifically and adequately accommodate all the changes that have occurred. As a result, the BOEM regional offices have always requested additional information from operators through NTLs, as contemplated in the preamble to the current rule to incorporate USEPA updates. Consequently, the amendments to subparts A, B, C and J of 30 CFR Part 550 are necessary to incorporate current USEPA ambient air quality standards and to ensure that any future changes to those standards are incorporated whenever they occur, thereby ensuring protection of those ambient standards in corresponding onshore air quality jurisdictions. Also, the amendments recognize current procedures used to determine the impact of air emissions and permit such procedures to be updated in the future to reflect advances in science, practice, and technologies, including those that take into account the unique conditions of the Arctic OCS.

With the implementation of this proposed rule, BOEM will have established standards to regulate all criteria and major pollutants and provide a regulatory mechanism in place to ensure that all of the updated NAAQS standards, published by the EPA in 40 CFR part 50, are fully complied with on an ongoing basis.

In specific, BOEM is proposing to amend these regulations to reflect:

> *Jurisdiction*. The proposed rule would address the division of jurisdiction between BOEM and EPA and automatically adjust to any future change in the division of jurisdiction. Also, the proposed rule allows for differences in information collection requirements based on whether BOEM or EPA has jurisdiction.
>
> *Movement of the Measurement Point for State Impacts*. The proposed rule would change the location(s) where air emissions will be measured and evaluated. BOEM is proposing

to measure state air quality impacts at the state/federal submerged lands boundary rather than the coastline.

- The state/federal submerged boundary is 3.4 statute miles for all states except Texas and the west coast of Florida where the submerged lands boundary is 10.3 statute miles.
- The compliance measurement point would be the closest point, or the point of greatest impact indicated by modeling. Traditionally BOEM only required measurement at the closest shoreline point.

Air Emissions Standards. The proposed rule would expand the number of pollutants that are subject to an air quality review and cross-reference the standards for those pollutants to those of the USEPA. Under existing regulations, air emissions above certain standards must be reduced using BACT, and in some instances, additional reduction measures or offsets may be required. These requirements generally continue in the proposed provisions; however, the regulations would replace BOEM's three circa-1980 standards with EPA's current standards and allow adjustments automatically to the rule as follows:

- New standards are added for $PM_{2.5}$, which is not defined as a distinct air pollutant under current BOEM regulations.
- A new emissions threshold is established for lead, and lead emissions would be required to be reported under the proposed rule.
- A new criteria air pollutant is designated as an air pollutant subject to NAAQS.
- The proposed rule would address all the air pollutants for which there are defined NAAQS and considered criteria pollutants. The list of criteria pollutants will update automatically through the cross reference to the EPA's NAAQS list.
- The proposed rule includes precursor pollutants. Any pollutant other than a criteria pollutant, for which States are required to report their emissions to the EPA is considered a major precursor pollutant under BOEM's proposed rule (and therefore subject to regulation by BOEM).
- A new air pollutant is identified as subject to a significance level or a maximum allowable ambient air increment.
- The proposed rule modifies the process by which BOEM can change the exemption formula which screens out low emission facilities from more extensive analysis. The change allows BOEM to update the emissions exemption formula within a range by publishing a notice in the *Federal Register* without rulemaking.

Addition of photochemical modeling. The proposed rule would provide for BOEM to mandate the application of photochemical modeling for the formation of ozone and $PM_{2.5.}$

- Photochemical modeling will be required if relevant precursor air pollutants (e.g., NOx) exceed the applicable emission exemption thresholds and approved air quality models are available. In the event that such photochemical modeling is required, operators would be required to take the relevant precursors for these pollutants into account in calculating the effects of offshore activities on state air quality.
- Additional emissions reduction measures could be required if photochemical modeling indicates that any Ambient Air Standard is exceeded, as a result of the formation of ozone or $PM_{2.5}$.

- Models must be USEPA approved, comply with the Federal Land Managers' Air Quality Related Values Workgroup Guidance or be approved by the BOEM Chief Environmental Officer

Modification of attributed emissions and measurement periods. The proposed rule would formalize the concept and application of the term "attributed emissions." This proposed change likely has the greatest impact on the regulated entities and imposes the greatest compliance cost. The following are the primary proposed changes:

- BOEM is proposing to explicitly require air emissions be evaluated on both a 12-month rolling average and a calendar-year basis rather than just a calendar-year basis.
- The definition for "facilities" is expanded to include those facilities involved in the transport of oil.
- Aircraft emissions are not required to be reported under most circumstances and are excluded from attributed emissions calculations unless modeled emissions are at 95 percent of the SIL.
- The definition of "attributed emissions" has been modified to include all support vessels and offshore vehicles operating in support of a facility regardless of the distance from the facility. The 25-mile radius limitation no longer applies.
- Criteria and precursor air pollutants emitted from any support vessel and offshore vehicle, described in a plan operating in support of a facility while above the OCS or state submerged lands, are included in attributed emissions.
- Attributed emissions from non-stationary sources are to be modeled based on the location from which they are emitted.
- Impacts from attributed emissions are proposed to be measured at the shoreline or the state/federal submerged lands boundary where pollutant concentrations are the highest.
- The exemption threshold distance calculation is measured to the closest distance to the state/federal boundary, or closest Class I area, whichever is shortest.
- Formalizes requirements for the consolidation of emissions from multiple facilities.
- Plan aggregation of proximate or complex total emissions may be required under certain circumstances and may require that more plans model or employ operational controls or BACT.

Emission Reduction Measures.

- Establishes new criteria for the application of operational controls or BACT.
- Modifies the definition of BACT from the existing rule. The existing rule defines BACT as an "emission limitation" based on the maximum degree of reduction for each air pollutant with consideration of energy, environmental and economic impacts, which essentially mirrors the federal definition of BACT in the CAA. The new rule redefines BACT as a "physical or mechanical system or device" that reduces emissions to the "maximum degree practicable" taking into account energy, environmental and economic impacts, which essentially implies a physical add-on control as opposed to an operational control method, which are generally "good combustion practices".

- Defines a new term called “Emission Reduction Measures” (ERM) which is a broad term encompassing any operational controls, equipment replacement, BACT, or emissions credits.
- Additional emissions reduction measures may be required if the Regional Supervisor determines cumulative impacts exceed previously estimated levels.
- A facility for which dispersion or photochemical modeling shows state or Class I area impacts must implement emission reduction measures in connection with additional dispersion modeling, to demonstrate the ambient air standards would be met.
- The requirements for applying emission reduction measures depend on technical feasibility, the amount of time a facility is anticipated to be at any given location and the attainment status of impacted areas.
- Lessee(s) must notify the Region and implement an equally or more effective alternative if any control technology becomes non-functional or unavailable.
- Emission offsets or credits are allowed from any source that is not in the same plan, not only from other facilities.
- Offsets, if proposed by a lessee or operator as an emissions control measure, must be of the sufficient magnitude to bring the plan under the SILs or AAIs as applicable.

Monitoring and Recordkeeping.

- Specify recordkeeping and reporting requirements for all approved plans
- Operators would be required to maintain fuel log data for attributed emissions and facilities. Reporting is at the discretion of the Regional Supervisor but is assumed in this analysis to include all plans above the exemption threshold in § 550.303(c)(1) or § 550.303.(c)(2) or employing emissions reduction measure(s). Exceptions are proposed for MSC activity if available from an independent third party. In most cases these monthly data are anticipated to be reported annually.
- If stack testing is used as a method to develop alternate emissions factors, stack testing must be conducted every three years to ensure emissions factors are still valid.
- The OCS emission inventory for regional air quality information reporting replaces the old Gulfwide Offshore Activity Data System (GOADS) and applies to the OCS area off the North Slope of Alaska.

Other Changes.

- Specifies that oil and gas exploration or development plans that require modeling will be required to use the methodology described in USEPA’s Appendix W.
- Modifies the process by which exemption thresholds are established and updated.
- Expands the current requirement that BOEM may require, after considering objections from states or tribes with EPA-approved tribal implantation plans, additional information and impose additional requirements if BOEM determines there is a significant potential impact to states’ air quality.
- Allows regional directors to require lessees to submit a revised plan if applicable air standards change.

- Establishes new criteria and processes for the evaluation of emissions from facilities after the plan has been approved by requiring plan resubmission at least every 10 years to reevaluate air quality impacts.
- Requires for non-exempt plans, the modeling of 1-hour, 3-hour, 8-hour and 24-hour emissions levels, or other time intervals as specified in the relevant USEPA tables.
- Data, needed for reviewing Class I or Class II areas, is provided to Federal Land Managers for consultation purposes.
- Elimination of exemption from rule for facilities constructed before 1980.
- The Regional Supervisor may require the installation and monitoring of monitoring systems to measure and evaluate air pollutant emissions.

The proposed rule would not by itself alter any of the existing emissions exemption levels for either the GOM OCS west of 87.5^{o}W longitude nor for the Arctic OCS. With the exception of lead, the existing exemption thresholds at § 550.303 (1980) remain in effect until regional studies are completed. Following completion of these studies in 2018, BOEM will analyze the results and then consider whether to revise the exemption thresholds for each region. If BOEM proposes to revise the exemption thresholds outside of the upper and lower bounds in the proposed rule, it will do so through notice and comment rulemaking.

BASELINE

For this rulemaking, BOEM assumes the same regulatory baseline for the two regional OCS areas under the Department of Interior's (DOI) air quality jurisdiction. This baseline is the current regulations and established current procedures for more than 35 years of DOI administered air-quality jurisdiction in the GOM. BOEM derives this proposed rule's compliance cost estimates using the existing regulations and established procedures in the GOMR for the approval of EPs and DOCDs.

In general, under existing regulations, EPs, DPPs or DOCDs submitted by operators must show regulated air pollutant emissions to be below the exemption threshold or below the SILs. If the plan's maximum estimated emissions are below the exemption threshold, no additional modeling or controls are required under the current or proposed regulations. If the maximum emissions are above the exemption threshold, lessees must model actual emissions to determine if the plan's emissions will remain below the SILs. If a plan's emissions exceed a SIL, then the existing regulation requires that the operator implement BACT to reduce the impact of the emissions. For plans with emission reduction measure(s), lessees must provide reports of actual activity or verified air emission rates to ensure the plans' emissions are below the exemption threshold. If actual emissions are above the exemption threshold, plans must employ BACT or offsets.

That general approach to regulating emissions is unchanged between the current regulation (baseline) and the proposed rule. The proposed rule modifies the current one in a number of ways, and the incremental costs and benefits associated with the modifications are estimated in this RIA.

Arctic air quality jurisdiction returned to DOI in December 2011. Potential minor differences in practice between the GOM and Alaska OCS Regions implementing current BOEM air quality regulations do not result in material compliance cost differences for this proposed rule. Practical differences would be minor and the sheer annual quantity of GOM EPs and DOCDs dwarf the one or two plans BOEM expects to receive each year in the Alaska OCS Region. The current Alaska practice is similar to the EPA and the incremental costs imposed by this rule above the current baseline are small or negligible. Many of the methodologies used in the Alaska Arctic to evaluate plan emissions are being codified in the regulations for the first time.

REGULATORY COMPLIANCE COSTS

The proposed rule would provide that BOEM cannot approve a plan that would generate emissions exceeding the NAAQS, thereby causing an area of a state to switch from attainment to a non-attainment status. Any facility that demonstrates projected emissions in excess of the SILs would be required to demonstrate that those emissions do not cause an exceedance of any NAAQS. BOEM's proposed changes for the OCS air emissions requirements clarify attributed emissions and measurement periods and change the resulting cases where air dispersion modeling, photochemical modeling, monitoring or ERMs will be required. The compliance costs for this rulemaking primarily relate to these items and will be overwhelmingly borne by plans in the GOM. BOEM estimates modeling expense comprises about 24 percent of the additional compliance cost, monitoring represents 28 percent of the compliance cost and ERMs are 36 percent of the cost over the 10-year period of this analysis. The remaining 12 percent of air quality compliance costs are for additional paperwork burden hours identified in the PRA for operators submitting plans.

Table 2 Compliance Cost Summary

Summary of AD82 Quantified Compliance Costs (nominal dollars in millions)										
Years →	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Modeling (§ 550.303)	$0.9	$1.0	$1.0	$11.8	$11.8	$11.8	$11.8	$11.8	$11.8	$11.8
Monitoring (§ 550.311 & 550.312)	$3.0	$4.3	$5.4	$6.5	$7.4	$8.3	$9.0	$9.8	$10.4	$11.0
Emissions Reduction Measures (§ 550.307)	$15.9	$21.2	$25.9	$25.9	$20.6	$11.2	$5.3	$4.7	$0.0	$0.0
Miscellaneous	$3.1	$3.4	$3.5	$5.1	$5.1	$5.1	$5.1	$5.1	$5.1	$5.1
TOTAL COSTS:	**$22.9**	**$29.8**	**$35.8**	**$49.3**	**$44.9**	**$36.4**	**$31.3**	**$31.4**	**$27.4**	**$28.0**

BOEM estimates that for plans requiring modeling, some may exceed the SIL for at least one pollutant and measurement period. Table 3 estimates the future number of plans reviewed by BOEM, those requiring air quality modeling and the results of those modeling efforts. A plan's air quality impact can only be known though modeling and air dispersion modeling was not specifically conducted for this analysis. The proposed provisions summarized in Table 4 drive the increased number of plans that may exceed the SIL for one pollutant or measurement period. The following assumptions are made regarding the estimates in Table 3:

- Alaska DPP or EP results will not materially differ between the baseline and proposed rule so Alaska Plans are not included in Table 3.
- These estimates considered 2013 and 2014 plan submissions in conjunction with declining OCS activity over the next few years and the impact of the applicable proposed rule provisions.
- This table provides BOEM's best plausible estimate for the number of plans that may fall into the categories listed beginning in 2017.
    - The provisions proposed in this rule will increase the number of plans that must model.
    - The plan counts in these categories may not solely be the result of the provisions in this rulemaking and include plans that would be required to conduct modeling under the baseline.
- The number of plans indicating impacts over the SIL is expected to increase due to line source modeling, attributed emissions and movement of the compliance measurement point.
    - BOEM assumes the attributed emissions provisions and line source modeling will be effective in 2017.
    - BOEM assumes the movement of the compliance measurement point to the state-federal submerged lands boundary will be effective in 2020.
- Beginning in 2020 BOEM estimates that up to 15 DOCD plans per year will require resubmission due to the 550.310(c) provisions. None of the 550.303(c) plans are estimated to exceed the EET since plan drilling or construction operations resulting in increased emissions would almost certainly require a revised plan before the 10-year mark.

Table 3 Estimated Plan Air Quality Results

#GOM Plans	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Plans over SIL (attainment area) but under AAI	5	6	7	14	14	15	15	15	15	15
Plans over SIL (nonattainment area) or exceed AAI	2	2	1	1	1	0	0	0	0	0
95-100% of SIL (remodel)	3	3	4	5	5	5	5	5	5	5
Plans Over EET; No SIL Exceedance	45	47	49	60	60	60	60	60	60	60
Plans Under EET (no modeling)	143	160	179	196	200	200	200	200	200	200
TOTAL:	**198**	**218**	**240**	**276**	**280**	**280**	**280**	**280**	**280**	**280**

The estimated impact and proposed rule compliance costs are tremendously uncertain. The compliance cost estimates in this section do not include future exemption formula or modeling changes resulting from the ongoing regional air quality modeling studies in the GOM and Arctic OCS. BOEM's assumption for Gulf coast onshore NAAQS attainment status uses EPA 2011-2013 monitoring data. The 2014 and [preliminary] 2015 ozone monitoring data indicate that certain Louisiana onshore areas identified as ozone nonattainment during the early years of this analysis, may achieve attainment when the USEPA updates the attainment status using the 2014-2016 monitoring data. The EP, DOCD/DPP plan activity levels and corresponding drilling activity may be higher or lower than estimated in this analysis and depends on a multitude of factors. BOEM will update assumptions for the final RIA and welcomes comments or improved information for improving the analysis of impacts and estimated regulatory compliance costs.

Modeling Compliance Costs

Both the existing regulation and the proposed rule require the modeling of emissions that exceed the exemption threshold to determine impacts on affected states. The modeling compliance costs resulting from the proposed provisions in this rule reflect:

1. Increased cost of air dispersion modeling for consideration of all mobile sources to the shoreline or state/federal submerged lands boundary.
2. Increased number of plans that must provide air dispersion modeling as part of the air quality analysis due to the proposed provisions in this rulemaking.
3. New cost of photochemical modeling ($PM_{2.5}$ & O_3) when a precursor pollutant exceeds (assume NO_x for this analysis).

Modeling: Baseline

BOEM's current regulations require air dispersion modeling of a plan's emissions that could potentially impact air quality onshore. BOEM allows air dispersion modeling to assign all emissions within a 25-mile radius to the point source for estimating the air quality impact at the shoreline. Under the baseline scenario, about 20 plans a year are required to conduct dispersion modeling under BOEM's current air quality regulations. Occasionally, operators provide BOEM with air dispersion modeling data for NEPA purposes, but these modeling efforts are not considered to be part of this rule's regulatory baseline. BOEM estimates the air dispersion modeling costs (with all emissions assigned to the point source) currently to run about $10,000 per modeling run and report.

An EP, DOCD, DPP, ROW or RUE may be submitted or resubmitted several times during the life of a project, and some plans are resubmitted several times in a single year. If the levels of emissions increase because of changes to the project, the operator must update the air quality analysis and resubmit to BOEM for review.

For plans that exceed the exemption threshold, current regulations require operators to conduct modeling that allows BOEM to determine whether emissions from any facility could cause an exceedance of the NAAQS onshore. If modeling shows a facility will exceed the SILs, the NAAQS is potentially impacted. BOEM regulations require mitigation measures or controls on the proposed exploration and development activities to reduce the impact on affected States. Based on the historical profile of pollutants, NO_x is the pollutant that is most likely to exceed the exemption threshold. Accordingly, the analysis in this section for both air dispersion modeling and photochemical modeling assumes that NO_x is the pollutant exceeding the exemption threshold.

Air Dispersion Modeling

The provisions in the proposed rule would increase the number of plans requiring modeling and, we estimate, double the air dispersion modeling costs from $10,000 to $20,000 per modeling report. This increased cost results from the requirement to model all project related vessels as line sources between the proposed project and the shoreline, rather than assigning Mobile Support Craft (MSC) emissions within 25 miles of the project to the point source.

For plans required to model emissions, the proposed rule requires air dispersion modeling results to be compared with the USEPA's SILs and in some cases the AAIs. Plans that would result in operations that generate emissions above the SILs as modelled are subject to further review, analysis and ERMs.

Operators would compare modeling results with the SILs in the USEPA table at 40 CFR 51.165(b)(2), as amended. If the modeling results exceed the SIL for any criteria air pollutant for any averaging time, ERMs would be required as specified in § 550.306, for a short-term facility, or as specified in § 550.307, for a long-term facility. The proposed regulations would require the modeling of one-hour emissions, as well as emissions generated over other relevant time intervals.

In addition to the increased cost for offshore air dispersion modeling there are six proposed changes in the rule that are expected to "pull" more plans above the exemption threshold and thus require modeling that would likely be absent from the existing baseline.

1. The proposed rule (§ 550.205(i)) moves the compliance determination boundary for state air quality impacts from the coastline to the federal/state submerged lands boundary. This change of the compliance determination boundary is for both the exemption threshold formula and air dispersion modeling. For all states except Texas and the west coast of Florida the compliance determination boundary will be 3.4 statute miles closer to OCS projects. For Texas and Florida, the compliance determination boundary will be 10.3 statute miles closer to OCS projects. The requirement to utilize the distance of the facility from the State/Federal boundary for the exemption threshold formula and state impacts would be effective after BOEM's exemption study is complete and public comments are solicited and reviewed. BOEM estimates this change will be effective in the year 2020.
2. The proposed rule (§ 550.205(e)) requires emissions to be evaluated based on a 12-month rolling basis rather than a calendar-year basis. Under the baseline some plans may have avoided exceeding the exemption threshold because operations proposed under a plan straddled two calendar years.
3. The proposed rule (§ 550.205(d)) eliminates the BOEM practice of only including MSC emissions within a 25-mile radius. The rule would require attributed emissions to include all emissions from support vessels, above the OCS or State submerged lands that support facility operations regardless of distance. This provision will increase the number of plans requiring modeling and, we estimate, double the air dispersion modeling costs from $10,000 to $20,000 per modeling report. This increased cost would result from the requirement to model all project related vessels as line sources at numerous points between the proposed project and the shoreline, rather than assigning emissions only from project related sources within 25 miles of the project to the facility location. The increased effort to input, analyze and describe mobile sources' possible impact on the shoreline and other receptor points are the drivers of the increased modeling cost.
4. The proposed rule (§ 550.303(d)) requires the consolidation of emissions from multiple facilities wholly or partially owned or controlled by the same operator that are intended to be part of one unit or project. Those facilities would be combined for analysis and reported as complex total emissions under certain circumstances. The proposed rule would require a lessee or operator to add together emissions generated by proximate activities within one nautical mile from multiple facilities whether or not they are described in a single plan. The term "proximate activities" is defined in § 550.302.
5. If modeling shows projected emissions at 95% or more of a SIL, operators must remodel following any emission reduction measures or addition of aircraft emissions and applicable emissions from onshore support facilities (§ 550.205(m)).[2]
6. The proposed rule (§ 550.303(c)) is written to accommodate the future results of the ongoing BOEM study to re-evaluate the exemption thresholds and exemption formulas.

[2] Given that aircraft emissions typically account for less than 2% of the total emissions associated with a plan, this requirement is not expected to cause many plans to exceed the EETs. Regardless, however, the requirement to report aircraft emissions already exists in BOEM's regulations at 30 CFR 550.224 and the proposed rule generally reduces these requirements, rather than increase them.

The new formula will be tailored to the relevant environmental characteristics of each region and take into consideration USEPA standards applied to various time periods. If the proposed rule is adopted, a future rulemaking will not be required to change the exemption formula within the range proposed in the rule. It is impossible to know the future result of the exemption studies for the GOM or Arctic OCS. Accordingly, BOEM is not estimating the potential results or impact of this ongoing study in the estimated compliance costs for this rulemaking. A sensitivity analysis is provided in Figure 1 which considers the modeling efforts that may be required under several different assumptions to provide the public a context for possible compliance costs when a new exemption formula is implemented.

The impact for the proposed changes numbered 2 to 6 are difficult to independently predict because of ongoing changes in OCS operations and potential operator changes to proposed plans. BOEM is estimating the compliance costs for provisions numbered 1-5 listed above. The compliance costs for provision #6 are considered too speculative to be estimated at this time.

The number of additional plans exceeding the exemption threshold because of the movement of the compliance determination boundary from the coastline to the federal-state submerged lands boundary (provision #1) is the most certain of BOEM's modeling estimates. Table 4 summarizes BOEM's estimate for the annual number of initial, revised or supplemental plans receiving air quality reviews that will exceed the exemption threshold and be required to provide air dispersion as part of the air quality analysis. This analysis is based on plans submitted during 2013 and 2014 and assumes that NO_x will be the pollutant exceeding the exemption thresholds. Due to the recent decline in oil prices BOEM's scenario estimates that fewer plans will be submitted during the years 2017 to 2020 but would resume the baseline levels of 2013-2014 thereafter. Table 4 provides the estimate for years 2020+.

Table 4. Number of GOM Plans Each Year Requiring Modeling

Provision	#Plans/ year	Notes on Modeling
Historical Baseline	20	About 20 out of about 265 plans receiving air quality analysis are subject to air dispersion modeling in a typical recent year.
1. Measurement pt. moved from shoreline to F/S submerged lands boundary	30	About 30 additional plans are expected to exceed the current exemption threshold if the compliance determination boundary is moved 3.4 sm or 10.3 sm off TX & FL.
2. Rolling 12-month average	10	About 10 additional plans may be pushed above the emission threshold and require modeling due to measurement of emissions on a 12-mo rolling average rather than calendar year basis.
3. 25-mile measurement	5	About 5 additional plans may be pushed above the

radius eliminated		exemption threshold and require modeling when all support emissions are included. Support vessel emissions would be included whenever a vessel is operating in support of a regulated facility, regardless of distance.
4. Consolidation of emissions for proximate facilities for the same Operator	15	About 15 additional plans per year may require modeling when all required proximate or project emissions are analyzed together.
5. Remodeling for those plans that are at 95% of the SIL or apply ERM.	20	If the projected emissions (analysis assumes NOx) are modeled at 95% of the SIL, operators must remodel following any emission reduction measures or addition of aircraft emissions and applicable emissions from onshore support facilities (§ 550.205(m)). BOEM estimates that up to 20 plans per year will require remodeling.
6. Exemption formula change	Too speculative to estimate	Proposed § 550.303(c) could require modeling for all plans with emissions over 100 tpy of NOx near shore and about 660 tpy of NOx at 200 nm. If the lower-bound threshold is applied about 90 percent of all plans would require modeling. If the exemption formula remains unchanged, no additional plans would require air dispersion modeling due to this provision.
TOTAL:	100	BOEM estimates that excluding changes based on exemption formula studies, 60 additional plans may require initial modeling each year under the proposed rule plus 20 plans will require remodeling due SIL exceedance. Including the current baseline of 20 plans a year receiving modeling, a total of 100 plans per year are expected to require modeling absent a change in the distance-based exemption formula.

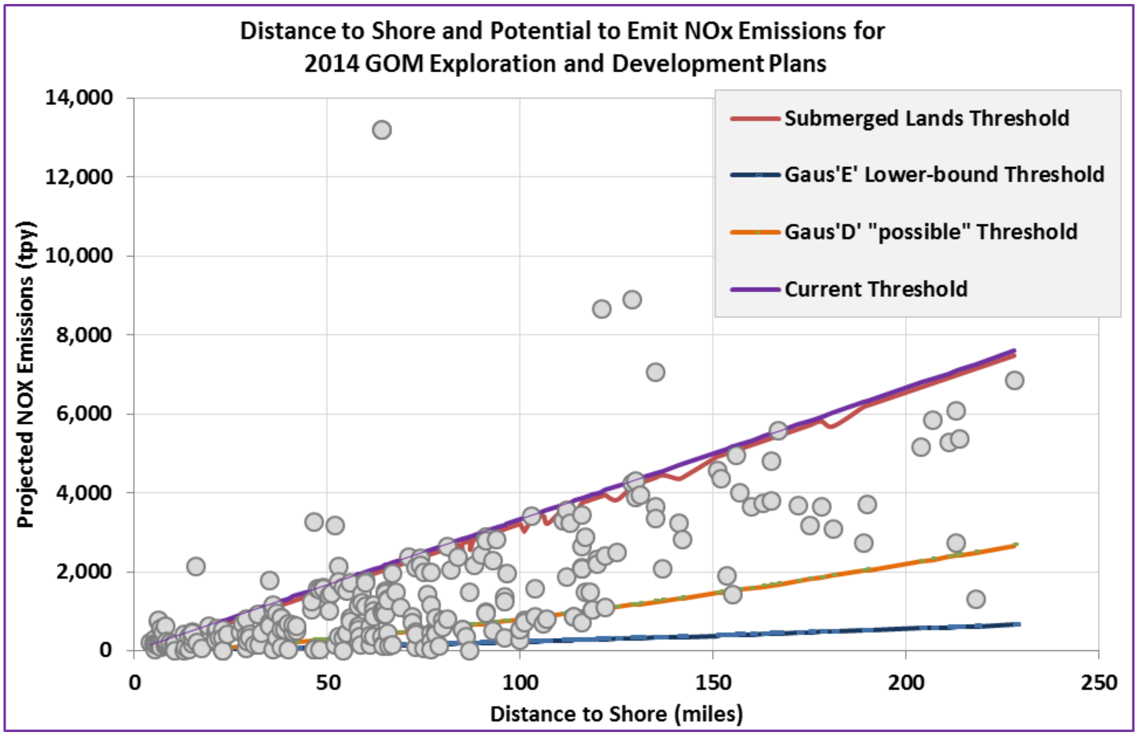
Of the ~265 plans BOEM reviews for air quality impacts each year, a baseline of approximately 20 plans submit modeling reports each year. Under this NPRM about 60 additional plans are estimated to include modeling reports for a total of 80 plans submitting modeling reports. Of these 80 plans about 25% (20 plans) are anticipated to submit a second modeling analysis due to the requirements in § 550.205(m). The remaining 185 plans (265 – 80 = 185) are not expected to submit modeling reports because the estimated emissions are below the distance-based emissions thresholds. This estimate of 80 plans is based on the existing exemption threshold. The results of the ongoing GOM and Alaska regional exemption studies will significantly change the number of plans required to model. BOEM does not have a basis at this time to estimate the direction or magnitude of this change.

Figure 1 displays the "potential to emit" NOx emission estimates for 2014 plans submitted to BOEM for Air Quality Analysis. The four lines on the graph represent the four exemption thresholds considered in the RIA analysis.

- Regulatory baseline under the current exemption threshold (purple line).
  - About 8 percent of plans or 20 per year are required to conduct air dispersion modeling under the baseline.
- The Submerged Lands Threshold (red line) is the current exemption threshold adjusted to the compliance determination boundary at the state/federal submerged lands boundary.
  - The squiggles in the line represent the different compliance determination boundaries for TX and the rest of the Gulf States.
  - About 20 percent of all plans would need to conduct air dispersion modeling under this scenario absent any change in the exemption threshold.
- The blue Gaus'E' line[3] represents the lower bound threshold in the proposed rule and only is relevant following the completion of the Alaska and GOM exemption studies when a new exemption threshold will be implemented for each region.
  - This line represents an atmospheric stability *Category E* (slightly stable) assumption.
  - If the exemption studies determine a threshold this strict, about 90 percent of plans would need to conduct air dispersion modeling under the Gaus'E' scenario.
- The orange Gaus'D' line represents BOEM's sensitivity analysis assumption.
  - This exemption threshold line represents an atmospheric stability *Category D* (neutral) instead of the stability Category E used for the proposed lower threshold.
  - At ~200nm the lower limit is about 662 tpy/yr [Gaus'E']; the [Gaus'D'] lower threshold is about 2,737 ton/yr.
  - About 80 percent of all plans would need to conduct air dispersion modeling under the Gaus'D' assumption

[3] The E and D lines are air stability factors. The rulemaking docket includes the methodology and analysis BOEM used to develop these thresholds.

Figure 1. NOx Air Dispursion Modeling Scenarios (GOM)



Air Dispersion Modeling Compliance Costs

Air dispersion modeling is well established and the meteorological data are available. BOEM estimates that air dispersion modeling for most GOM projects will cost about $20,000 per modeling run and report. This is an increase above the current $10,000 estimated air dispersion modeling cost due to the proposed rule's requirement to model all support vessel emissions between the port and the facility at the specific locations where they occur, rather than only modeling MSC emissions within a 25 mile radius and combining those emissions to a single point source as currently practiced under the existing rule. This modeling of support vessel emissions may require multiple model runs with support vessels modeled in different possible locations to identify the worst-case impact on the receptor points. The increased effort to input, analyze and describe mobile sources possible impact on the shoreline and other receptor points are drivers of the increased modeling cost.

The additional annual air dispersion cost for 20 (baseline) plans ($10,000 additional cost per modeling effort) is a cost of $200,000.

Additional Plans Subject to Air Dispersion Modeling

The provisions in this proposed rule are expected to result in some plans above the existing threshold that would not be under the existing rule. These plans would be required to conduct air dispersion modeling due to proposed requirements #1 to #4 summarized in Table 4 above. About 25 additional plans are expected to submit modeling reports due to proposed requirements 2 to 4 in 2017 (year 1) rising to 30 plans in 2020 as the drilling activity recovers. The movement of the state/federal compliance determination boundary is expected to be implemented in early 2020 (year 4) and result in about an additional 30 plans that will be required to provide air dispersion model reports. A total of about 60 out of 265 plans per year are expected to require air dispersion modeling due to the proposed changes in this rulemaking. Remodeling following application of emissions reduction measures or adding aircraft emissions yields another 20 modeling efforts.

Summary of Air Dispersion Modeling Costs (Proposed Rule)

Table 5 summarizes BOEM's estimate of the additional air dispersion modeling costs required due to the provisions in this proposed rulemaking. This table shows the costs beginning in 2020, when the compliance boundary is expected to be moved from the shoreline to the state-federal submerged lands boundary.

Table 5. Dispersion Modeling Annual Cost Summary (2020+)

Regulatory Provisions	Est. Cost
Increased air dispersion modeling cost (mobile sources increment)*	$200,000
Additional plans and pollutants requiring air dispersion modeling**	$1,600,000
TOTAL:	**$1,800,000**
*20 plans/yr at $10,000 additional cost for modeling mobile sources **100 plans/yr at the $20,000/run-report modeling cost for air dispersion modeling [minus baseline plan costs].	

Dispersion Modeling Cost: Alternative Scenario

If the regional exemption studies support an exemption formula similar to that predicted by a Gaussian formula with a stability category D (see Figure 1 above), about 80 percent of all plans would be required to conduct air dispersion modeling. The proposed rule would only require a notice in the Federal Register to implement the new exemption formulas following completion of the regional exemption studies. However, because of the uncertainty regarding each regional study result, BOEM is using a stability category D Gaussian formula to provide a sensitivity estimate for additional air dispersion modeling costs when the regional exemption studies are complete. Assuming about 80 percent of all plans would be required to conduct air dispersion modeling, 212 out of the total 265 plans would be required to conduct air dispersion modeling for five pollutants. Given our previous estimate of $20,000 per modeling effort, BOEM calculates the total annual cost to be ~$4.2 million. Under the current exemption formula and with the movement of the state compliance determination boundary to the state/federal submerged lands boundary, the proposed rule scenario assumes that 80 plans will require modeling each year, costing $1.6 million per year. Therefore, the incremental regulatory compliance cost for dispersion modeling under the Gaus'D' scenario is estimated to be about $2.6 million per year.

Photochemical Grid Modeling

Photochemical Grid Modeling (PGM) can predict ozone and regional haze impacts for major pollutants and precursors. PGM can evaluate impacts even after the precursor pollutants have been transported hundreds of miles. As a result of improvements to single source photochemical modeling capabilities, it is now possible to evaluate how the emissions of particulate matter and ozone precursors may contribute to particulate matter and ozone formation and how this may affect the air quality of the States. There are between 90 to 150 photochemical reactions accounted for in PGM models and literally millions of individual calculations which require great computing power and sometimes weeks of computer run time. This makes PGM much more expensive than air dispersion modeling.

The proposed rule would require photochemical modeling of particulate matter and ozone when projected emissions exceed the applicable emissions exemption threshold for NOx, VOCs, or CO. Based on the historical emissions profile of plans submitted to BOEM, NOx is the pollutant that will be exceeded, and is a precursor pollutant for both ozone and $PM_{2.5}$. Therefore, each exceedance of NO_x will require two PGM runs and reports; one for particulate matter and one for ozone.

BOEM expects that EPA will approve photochemical modeling protocols and models and modify its regulations at 40 CFR part 51 Appendix W around the year 2018. When the EPA publishes the final Appendix W in 2018, it is also expected to issue photochemical modeling guidance for onshore sources. Following the EPA approval of appropriate photochemical model(s), the BOEM Chief Environmental Officer can decide whether to require photochemical modeling for plans exceeding the exemption threshold for applicable precursor pollutants. Currently BOEM expects to approve and require photochemical modeling reports beginning in 2020. The year 2020 will provide BOEM sufficient time to both evaluate the applicability of EPA approved PGM protocols and the completed regional exemption study results. The estimated PGM costs for this proposed rule assume BOEM approves a PGM model in 2020 and two PGM runs and reports (one each for $PM_{2.5}$ and O_3) will be required for each NO_x exceedance.

Photochemical Modeling Costs

Cost estimates for photochemical grid modeling vary from $40,000 to $80,000 per modeling effort and report. These estimates derive from conversations with the USEPA and consulting companies specializing in air quality compliance. BOEM is using a cost estimate of $50,000 per photochemical modeling effort to estimate the compliance costs.

As a precursor pollutant for $PM_{2.5}$ and ozone, NO_x is the driver for both air dispersion modeling and photochemical modeling. BOEM is using the same number of photochemical modeling efforts as air dispersion modeling efforts in this analysis.

Under the assumption that the exemption threshold will not change following the BOEM regional emissions studies, there would be approximately 100 plans per year that would be required to conduct air dispersion modeling. If we use the Gaus'D' assumptions, about 212 plans could be subject to photochemical modeling under the proposed rule.

Assuming the BOEM Director approved a photochemical model and modeling was required for plans with a precursor pollutant above the exemption threshold, the estimated regulatory compliance cost would range from $10.0 million (100 plans) to $21.2 million (212 plans) per year.

Modeling Cost Summary

Table 6 below summarizes the estimated ten-year costs associated with air dispersion and photochemical modeling. The costs are approximately $1.0 million in the first year and eventually increase to a peak of $11.8 million starting in the fifth year.

Table 6. Costs for Air Dispersion and Photochemical Modeling

$millions	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Air Dispersion Modeling	$1.0	$1.1	$1.1	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8
Photochemical modeling	$0.0	$0.0	$0.0	$10.0	$10.0	$10.0	$10.0	$10.0	$10.0	$10.0
Total:	$1.0	$1.1	$1.1	$11.8	$11.8	$11.8	$11.8	$11.8	$11.8	$11.8

Emissions Reduction Measures (ERM) Compliance Cost Estimates

This section explains the assumptions and scenarios for estimating ERM compliance costs and benefits of the proposed rule. The provisions of the proposed rule may require operational controls or post-combustion ERM. Regulatory alternatives are considered as well along with BOEM's estimate of the corresponding costs and benefits. Consistent with the RIA for other provisions, the scenarios assume that NO_x is the criteria pollutant that will exceed allowed emissions and require reductions.

Under the proposed rule, if a project's air dispersion modeling shows NO_x (or other criterial pollutant) emissions impacting the NAAQS of a State, emissions reduction measures are necessary.

- If the receptor shows an exceedance of a SIL from a long-term facility's emissions in a *nonattainment area*, the emissions reductions must be sufficient that the modeling shows the SILs are not exceeded.
- If the receptor shows an exceedance of a SIL from a long-term facility's emissions in an *attainment area*, emission reduction measures are required along with additional analysis that must show the AAIs are not exceeded.

BOEM's analysis of operator submitted plans indicates that MODU drilling is the primary activity causing plan's emissions to exceed the emission threshold. Therefore the analysis of required ERM is closely related to the expected drilling activity.

An overview of the analytical method of this section is given by the following points.

1. The region-wide compliance cost is represented as an increased cost per year paid for leasing affected drilling rigs, or alternatively the cost per year of purchasing emissions credits.
    a) "Affected rigs" refers to rigs that needed to have equipment installed or operational changes made so that the lessees that use them can be in compliance.
    b) It is assumed that the compliance costs incurred by affected rigs will be passed on to lessees as increased day-rates for their use of these rigs.
2. The approach for estimating the number of affected rigs that are active and associated with compliance cost can be described as follows:
    a) The first step is to determine the amount of drilling activity, which generates demand for MODUs and leads to submission of plans requiring air quality analysis. Below, the amount of drilling activity is represented by total number of MODUs active in the GOM.
    b) Theoretically the next step is to find the number of plans submitted that, when modelled, exceed the SILs in nonattainment areas, or the AAIs in attainment areas. However, while this RIA discusses these points, it does not draw a rigorous connection between number of plans and ERM costs. The reason is that the number of plans submitted is highly variable, as a lessee might submit several revised plans during a given [drilling] project, etc. Also, a single affected rig might be employed by more than one project. Thus, the RIA analysis simply makes a direct assumption about the number of MODUs that are affected in each year.
    c) Given the number of affected rigs in a year, the next question is whether the MODUs are impacting a nonattainment area – and in need of ERM or are they only impacting (above the SIL) an attainment area – and subject to operational controls rather than the more strict ERM or emissions credits?
3. The ERM methods cost and benefit estimates are addressed separately for operational controls, BACT and emissions credits.
4. The compliance costs assigned to the rule assume emissions credits are purchased.

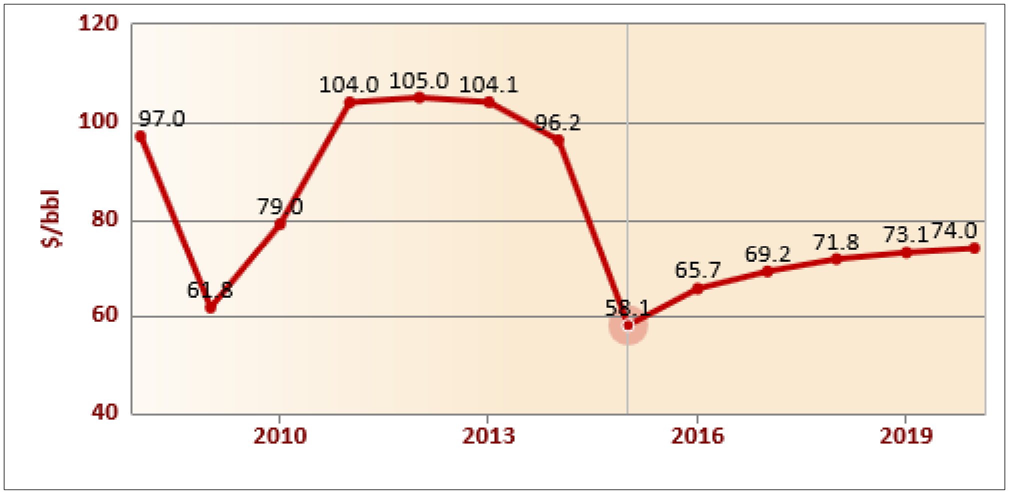
Oil and Gas Drilling Activity

This discussion provides the background and assumptions for a GOM scenario of the number of long-term facilities where NOx exceeds the SIL in state nonattainment areas.

The future intensity and locations(s) of oil and gas drilling activity are uncertain. As shown below in Figure 2, the mid-2015 crude oil price is historically low and expected to remain low for several more years at least. The projection for natural gas prices (not shown) is likewise low.

This outlook has led to a widely-recognized decline in rigs drilling in the GOM, especially in shallow water.

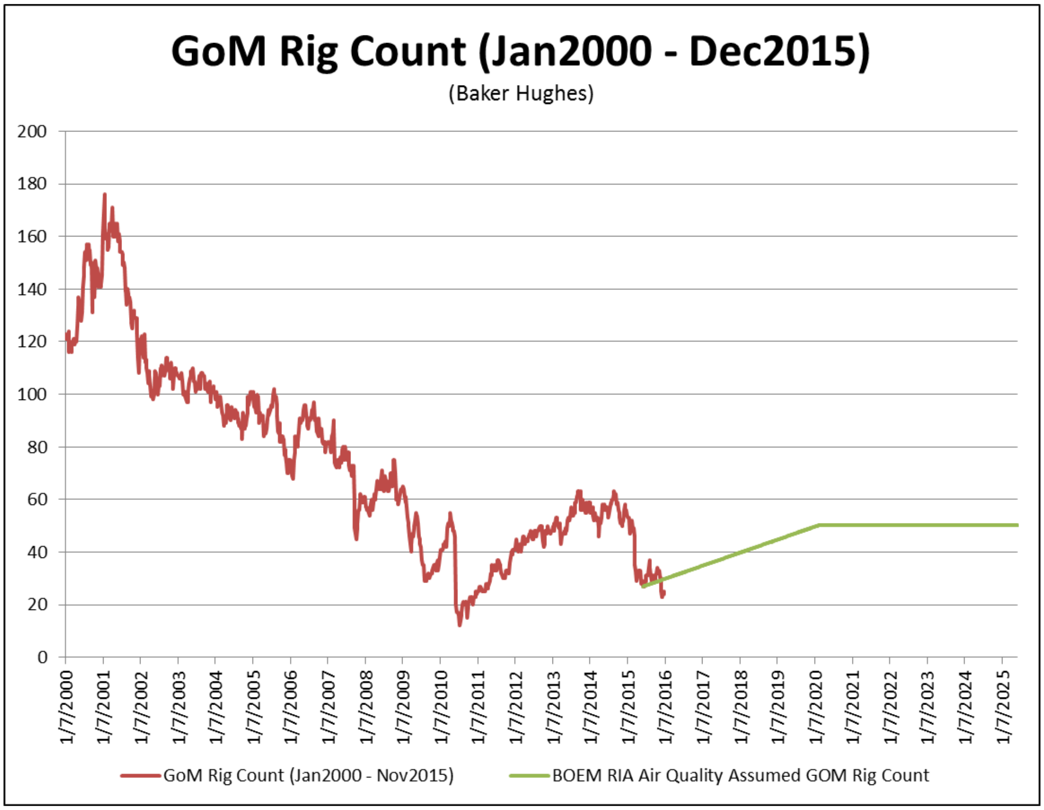
Figure 2. Recent and Forecasted World Average Annual Crude Oil Price (IMF 2015)



Despite the currently low level of prices, published forecasts generally expect a modest rise of prices over future years. With that rise, GOM deepwater drilling activity will likely recover. Specifically, deepwater activity may involve the employment of about 30 drillships and 10 semisubmersibles drilling by 2020 and after. The shelf activity may remain weaker, and it could employ up to 10 jackups as drilling recovers after 2020.

To represent these uncertainties, BOEM’s 10-year MODU drilling scenario, for purposes of this RIA, begins with about 27 drilling MODUs (mostly drillships) in June 2015 and rises in 2020 to the long-term average for the past decade, 50 MODUs, where it remains flat for the remainder of the scenario. The 50 MODUs include about 10 jackups, 10 semisubmersibles and 30 drillships in 2020. Figure 3 shows this future drilling scenario together with recent historical GOM rig count data.

Figure 3. GOM MODU Drilling Scenario, with Historical Data 2000-2015 (Baker Hughes)



MODUs Requiring BACT or other ERMs

Based on a review of GOM DOCDs and EPs, there are likely several development profiles each year that could require significant NO_x reductions to get below the SILs.[4] These projects are likely to be deepwater development projects employing at least two MODUs less than 100 miles from shore, or smaller shelf development projects close to the federal/state submerged lands boundary. Note that the greatest compliance costs are expected for deepwater projects, especially in the Mississippi Canyon area less than 100 miles from shore and in locations likely to impact nonattainment areas on the Gulf coast.

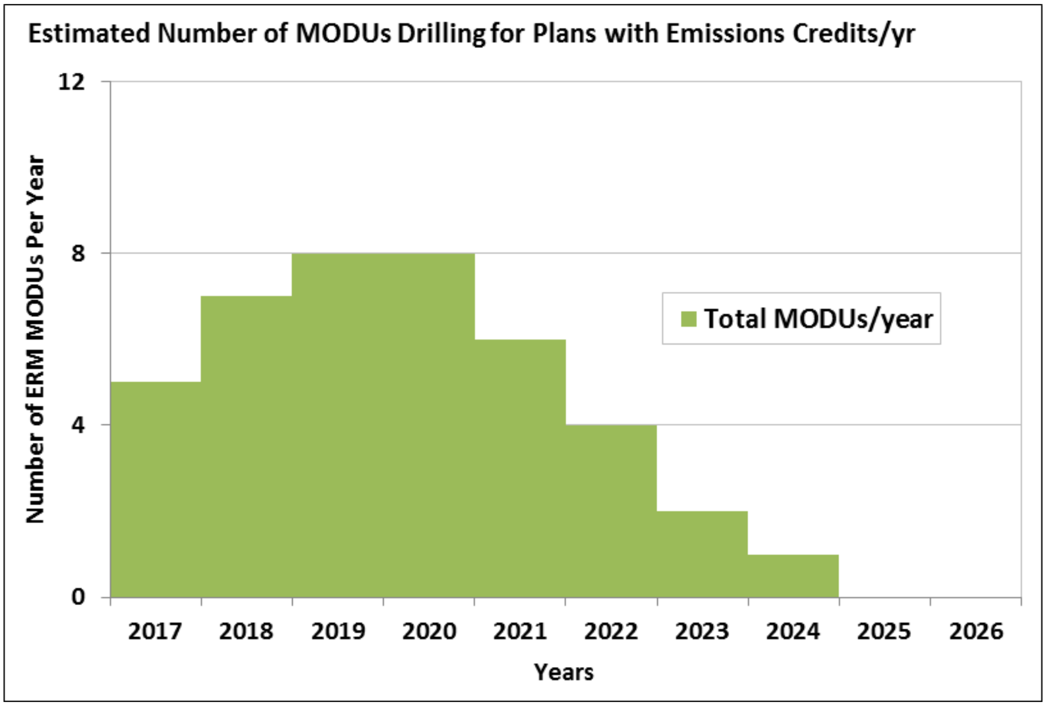
BOEM estimates that under the proposed rule up to 2 DOCD plans a year will have emissions levels that might exceed the NO_x SIL in nonattainment areas. One or two DOCD plans potentially employing multiple MODUs would be required to utilize SCR retrofit technology on category 3 marine engines, Tier-3 marine engines or NO_x emissions credits to lower NOx emissions under the SIL.

BOEM estimates the following number of MODUs (Figure 4) will potentially be part of long-term facilities where the air dispersion modeling is expected to show that the SIL is exceeded to

[4] The regional exemption studies will provide updated air quality modeling results for both cumulative and potential project impacts to state air quality.

such an extent that NOx emissions credits, SCR retrofitted engines or Tier-3 SCR engines will be required to lower the NOx emissions below the SILs for nonattainment areas. Because emissions credits are estimated to be the most cost effective mitigation, the analysis assumes each plan impacting a nonattainment area will purchase emissions credits rather than retrofit with SCR or Tier-3 engines.

Figure 4. Number of MODUs in Purchasing Emissions Credits



Number of ERM Candidate Plans

As mentioned above, the number of plans submitted and found to exceed the SILs is a critical factor in the actual compliance process; but for this discussion about the number of ERM required, it serves as background to ensure that scenario assumptions about rig counts are reasonable. Note that costs associated specifically with submitting plans and modelling are presented in the previous section and an estimate of GOM plans is provided in Table 3.

NO_x is the criteria pollutant BOEM expects to exceed the current exemption threshold, SILs or AAI.[5] A review of existing plans indicates that active drilling by MODUs is the main source of NOx emissions that will cause a plan to exceed the exemption threshold. The consolidation of plans required in § 550.303(d), movement of the compliance measurement point to the state seaward boundary, attributed emissions and the movement to a 12-month rolling average are all

[5] This analysis does not make assumptions regarding potential year 2020 changes to the emission exemption threshold.

drivers for the increased number of plans that BOEM expects to exceed the SIL and require ERMs.

In calendar year 2014, about 265 exploration or development plans were submitted to BOEM requiring air quality analysis. Under the existing regulations, 18 of the plans have maximum potential emissions that exceed the current exemption threshold (based on a factor of 33.3 tons of NO_x per year, per mile) and required modeling. Thus, if the pattern of that year is considered typical, a ratio of 18 plans (BOEM uses 20 in the analysis) out of approximately 265 will require modeling in the near term, given the existing emissions threshold formula.

BOEM found that almost 30 percent of the 2014 plans (i.e., 75 plans) applied emissions reduction methods or used verified alternative emissions factors that kept their projected emissions under the current exemption thresholds. Since the exemption threshold was not exceeded, these plans did not require air dispersion modeling. This issue is illustrated in Figure 1.

It remains uncertain how many plans or MODUs will require ERMs as a result of the proposed rule for several reasons:

- Under the proposed rule most plans would be required to include additional emissions in their air quality plan analysis due to the elimination of the 25-mile rule for attributed emissions, consolidation of plans and moving to a 12-month rolling measurement period rather than calendar year measurement period.
- The new exemption threshold identifying plans that require modeling is not yet determined (as the scientific study is not yet completed) and the emissions characteristics of future plans might not resemble the pattern observed in 2014.
- As noted earlier, projects that are likely to require modeling can take steps other than ERMs to reduce plan emissions. Where that is feasible, that would imply environmental benefits are generated at a lower cost than ERMs. Presumably lessees will attempt in various ways to reduce the emissions for their plans in order to avoid exceeding the SILS if feasible.

An analysis of plans submitted to BOEM in 2014 reveals that 45 of the plans exceeded the current emissions threshold (using the state seaward boundary) but 4 of the plans exceeded the threshold by more than 2,000 tons of NOx per year – a margin large enough that significant emissions reductions through the use of ERMs may be required depending on the distance from shore. The type of controls and level of pollutant reductions required depend whether the SIL exceedance is for an attainment or nonattainment area.

As a result of this analysis, assuming recent exploration and development patterns decline in the near term but will recover in the future, BOEM estimates:[6]

- 7 to 15 plans per year will model a criteria pollutant above the SILs with 1 or 2 of those each year impacting nonattainment areas. BOEM estimates that ERM (emission credits)

[6] This estimate assumes the 1-hour NOx SIL is reasonably foreseeable and will be finalized by the USEPA.

may be required for several years beyond a plan's approval or until the year 2025 when the USEPA expects Louisiana coastal political subdivisions to be in attainment for ozone.

Prospects for Nonattainment Status of GOM Counties 2016-2025

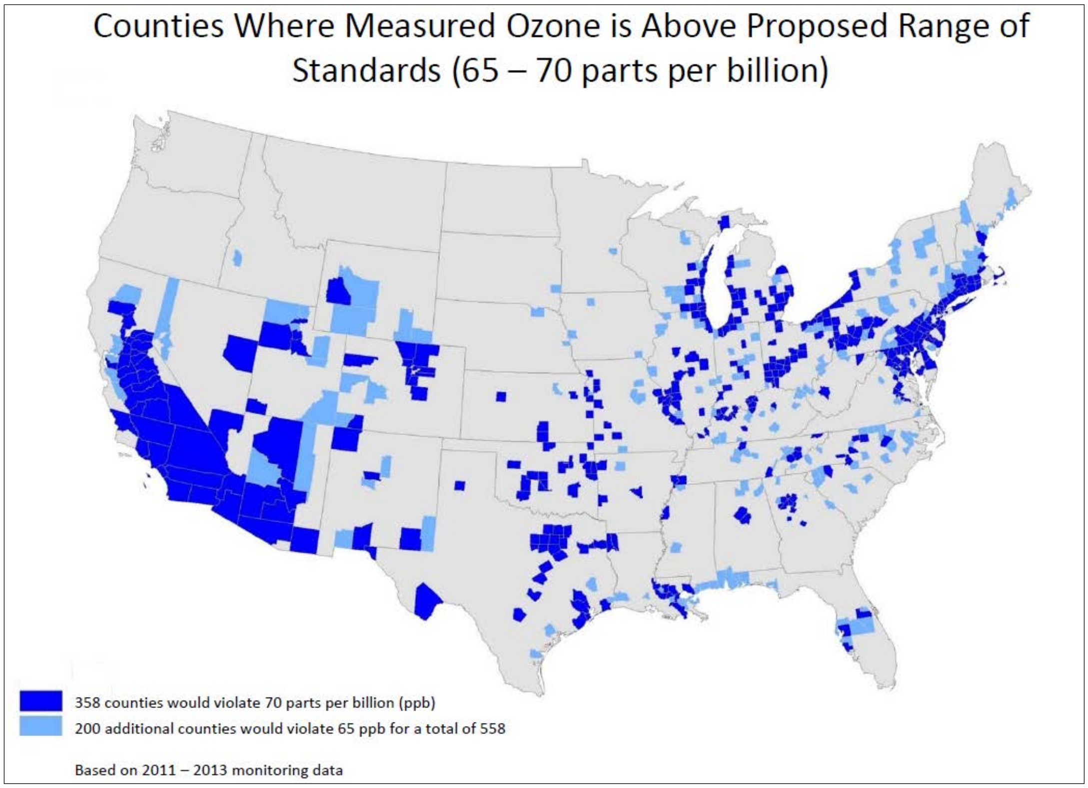
Per the regulations in § 550.305 and § 550.307, a long-term facility cannot exceed the SILs for a state nonattainment area. A long-term facility is one that expects to remain in place for greater than 3 years. By definition, development drilling MODUs will be treated as part of a project's long-term facility under the regulations even if the drilling occurs before the project's production facility is installed. Thus, critical assumption for the RIA is whether GOM coastal areas will be nonattainment areas over the time frame of the analysis.

EPA has indicated that under its final ozone rule threshold of 70 ppb, some Louisiana parishes and potentially other coastal GOM counties are likely to be nonattainment areas.[7] Under BOEM's proposed rule, the GOM shelf and deepwater development projects whose modeling results show emissions above the SILs will be required to reduce emissions below the SIL if impacting nonattainment areas.

[7] The USEPA intends to use 2014-2016 monitoring data to designate ozone nonattainment areas under the new 8-hour 70 ppb standard. The assumptions for this analysis use 2011-2013 monitoring data. Based on current ozone trends for coastal Louisiana parishes and Texas, Alabama, Mississippi and Florida counties, additional coastal political subdivisions may achieve less than 70 ppb for the 2014-2016 monitoring period. Ozone forms through secondary reactions and is heavily dependent on the local weather and level of emissions.

The following two figures (taken from EPA's proposed rule) show EPA's estimate of the coastal political subdivisions that are likely to be nonattainment areas under the new ozone standards of 70ppb.

Figure 5. Counties' Current Ozone Air Quality in Relation to Standards

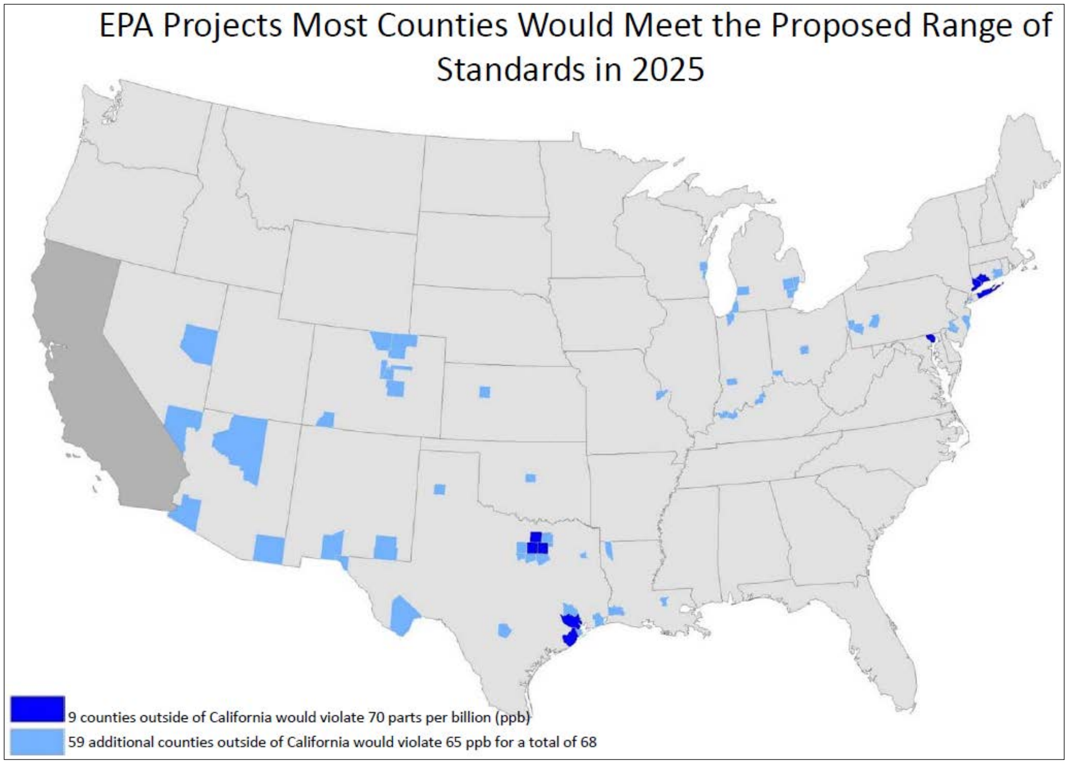


As shown in the map (Figure 5 above), and based on 2011-2013 monitoring data there are several Louisiana parishes that will likely be nonattainment areas under a 70 ppb standard. While additional counties in Texas and Florida may be categorized as nonattainment, modeled OCS emissions are not expected to indicate impacts above the SIL.

The primary port for vessels supporting OCS operations is Port Fourchon in Lafourche Parish, Louisiana. USEPA's 2011-2013 data show a concentration of ozone of 71 ppb in Lafourche Parish. Lafourche parish is likely to be one of the nonattainment areas where air dispersion modeling receptor information indicates the SILs are exceeded for long-term facilities in DOCDs.

As displayed in Figure 6, the USEPA expects continued improvements over the next decade for air quality. By 2025, all of the Louisiana, Mississippi, Alabama and Florida coastal political subdivisions are expected to be in attainment for ozone.

Figure 6. Counties' Future 2025 Ozone Air Quality in Relation to Standards **(USEPA)**



Therefore, toward the end of the 10-year time period of this RIA analysis, around 2025, BOEM expects the affected GOM coastal political subdivisions will be attainment areas so only operational controls will be required for plans submitted after that time provided the AAIs are not exceeded.

Sections 550.305, 550.306 and 550.307 Emissions Reduction Measures

Under the proposed rule and as discussed in the modeling section, there are several provisions in the rulemaking that will cause more plans to exceed the emissions threshold and require additional modeling and analysis. The largest lessee and operator compliance cost burden is expected to be incurred for long-term facilities that cause NO_x exceedance of the SILs in nonattainment areas. This higher compliance cost is driven by BACT or emissions credits that may be required to bring the plan emissions below the SILs. The flowcharts in the proposed rule's regulatory preamble provide decision-tree illustrations of the outcomes under different exceedance scenarios.

No plans have been required to adopt ERMs under the current regulations in either the GOM or AK. Some operators submitting GOM and AK plans have elected to commit to adjusting activity schedules or to keep their emissions under an exemption threshold.[8] Thus, the costs and

[8] If an operator elects to apply controls or mitigations based on a NEPA analysis or to avoid exceeding an exemption threshold, these costs are not considered to be a regulatory cost under this baseline.

benefits of ERMs required under the proposed rule would be entirely above the baseline. For the alternatives analyzed here, plans with long-term facilities are required to implement ERMs if modeling estimates NO_x emissions above the SIL in nonattainment areas or above the AAI in attainment areas.

ERMs can take a variety of forms including specific equipment requirements, procedural improvements, and many others. The available technologies have grown and improved over time and the most appropriate methods currently available vary by project depending on cost, types of equipment planned for use, etc. In an effort to simplify this benefit-cost analysis, a range of ERMs is considered on the large category 3 (>3,000 hp) marine engines: (1) best available control technologies (BACT), including Selective Catalytic Reduction (SCR) units and SCR Tier-3 marine engines, (2) emissions reduction credits, (3) equipment replacement and (4) operational controls.

ERM Compliance Cost Estimates for Short-Term and Long-Term Facilities

As discussed in the preamble of the proposed rule, BOEM is adopting new terminology for OCS facilities. A short-term facility would be defined as a facility on one location less than three years. It would most often be a facility covered in an exploration plan. A long term facility (including MODU drilling units) is generally a development project and is covered under a DOCD or DPP.

Operators are free to choose any methods or technologies available that effectively reduce NO_x emissions below the applicable thresholds. BACT "top-down" analyses conducted by the EPA and other agencies often take cost effectiveness into account and some agencies may grant exemptions if no available technologies are deemed cost effective. BOEM will consider the most cost effective option for emission reductions to meet its statutory mandate. This analysis assumes no cost effectiveness departures will be granted and plan emissions must meet the modeled (SILs & AAIs) thresholds.

Short Term Facilities

BOEM's responsibility is to evaluate the impacts of emissions necessary to avoid causing or contributing to a violation of the NAAQS and the air quality of States. If any short-term facility requires ERM under proposed § 550.305 for a criteria pollutant the lessee/operator is required to conduct an ERM analysis to determine potential control options and their likely cost effectiveness. Under the proposed rule, if it is determined through modeling that the planned operations for a short-term facility will generate a concentration of one or more air pollutants exceeding the SILs, but such exceedance only affects attainment areas, the lessee or operator would be required to demonstrate that its operations result in the greatest practicable reductions that are both technically and economically feasible through operational controls. Having done that, the plan could be approved while still causing an exceedance of the SILs. BOEM's proposed rule requires operators of short-term plans (§ 550.306(a)(5)) to:

> *Select reasonable operational controls or replacement(s) of equipment that are technically and economically feasible and that are designed to limit your facility's*

> *projected emissions to the greatest practicable extent, taking into consideration the effectiveness and the cost of implementation of each option considered. You must demonstrate that you have chosen the most effective technically y and economically feasible operational controls or replacement(s) of equipment for every pollutant requiring such controls that can be implemented cost effectively. As an alternative, you may propose an equivalent reduction through the use of emissions credits.*

If the projected emissions for the proposed facility exceed the SILs but such exceedance affects designated non-attainment areas for a specific pollutant, the Regional Supervisor may require the implementation of other ERM for that pollutant in lieu of operational controls or equipment replacement(s) as a condition of approving your plan. If the projected emissions for the proposed facility exceed the SILs, but such exceedance cannot be reduced through operational efficiencies or BACT, the lessee or operator may be required to apply emissions credits.

Based on EPA Region 4 analysis of OCS activities in the eastern GOM, BOEM does not expect that equipment replacement will yield cost effective reductions of criteria pollutants. So, the controls required by the Regional Supervisor for facilities above the SIL and only impacting an attainment area are expected to be operational controls, engine replacements, or emissions credits.

Long-Term Facilities

Under the proposed rule, in an *attainment area*, if emissions from a long-term facility were to generate concentrations of air pollutants landward of the State/Federal boundary in excess of the SILs, the lessee or operator would be required to undertake an ERM analysis, excluding BACT, to determine the most effective and technically and economically feasible approach for reducing the projected emissions from its facility. If the projected emissions for the proposed facility would cause an exceedance of the SILs landward of the State/federal boundary but would not cause an exceedance of the AAIs, the proposed plan could be approved without the lessee or operator having to lower its emissions so that the SILs would not be exceeded. If the projected emissions would cause an exceedance of the AAIs after the application of ERM, the lessee or operator would be required to use additional ERM or emissions credits until it could demonstrate its emissions no longer resulted in such an exceedance.

Under the proposed rule, in *a non-attainment area*, if emissions from a long-term facility were to generate concentrations of air pollutants within a state in excess of the SILs, the lessee or operator would be required to undertake an ERM analysis, including BACT, to determine the most effective and technically and economically feasible approach for reducing the projected emissions from its facility. If the projected emissions for the proposed facility continue to cause an exceedance of the SILs, the proposed plan could not be approved without the lessee or operator having to lower its emissions so that the SILs would not be exceeded. As for an attainment area, the operator would be free to propose emissions credits in lieu of any other ERM to accomplish this objective.

Operational Controls

Under the proposed rule, in an *attainment area*, if emissions from a long-term facility were to generate concentrations of air pollutants landward of the State/Federal boundary in excess of the SILs, the lessee or operator would be required to undertake an ERM analysis, excluding BACT, to determine the most effective and technically and economically feasible approach for maximizing the operational efficiency of its facility with respect to its emissions. If the projected emissions for the proposed facility would cause an exceedance of the SILs but would not cause an exceedance of the AAIs, the proposed plan could be approved without the lessee or operator having to lower its emissions so that the SILs would not be exceeded. If the projected emissions would cause an exceedance of the AAIs after the application of ERM, the lessee or operator would be required to use additional ERM until it could demonstrate its emissions no longer resulted in such an exceedance.

Under the proposed rule, in *a non-attainment area*, if emissions from a long-term facility were to generate concentrations of air pollutants within a state in excess of the SILs, the lessee or operator would be required to undertake an ERM analysis, including BACT, to determine the most effective and technically and economically feasible approach for maximizing the operational efficiency of its facility with respect to its emissions. If the projected emissions for the proposed facility continue to cause an exceedance of the SILs, the proposed plan could not be approved without the lessee or operator having to lower its emissions so that the SILs would not be exceeded. As for an attainment area, the operator would be free to propose emissions credits in lieu of any other ERM to accomplish this objective.

The decision on what operational controls for an operator to propose or BOEM to require under proposed § 550.306 and § 550.307 may be complicated given proposed provisions in the United States Coast Guard proposed rule, *Requirements for MODUs and Other Vessels Conducting Outer Continental Shelf Activities with Dynamic Positioning Systems* (79 FR 70944). The proposed rule was published on November 28, 2014 and the comment period was later extended until May 27, 2015. The Coast Guard's proposed rule would establish minimum design, operation, training, and manning standards for mobile offshore drilling units, or MODUs, and other vessels using dynamic positioning systems to engage in Outer Continental Shelf activities. The rule is designed to decrease the risk of a loss of position by a dynamically-positioned MODU or other vessel that could result in a fire, explosion or subsea spill. The rule states that "*degradation can occur when an operator of a vessel with a DP–2 system chooses to operate with closed bus ties and minimize the number of generators online in order to save fuel and avoid wear and tear on equipment. By doing so, the redundancy afforded by DP–2 may be compromised*." The Coast Guard estimates that 322 future OSVs, 57 future MODUs, and 20 future crewboats would be impacted by its proposed rule. The vast majority of these vessels are in the GOM.

The practical result is that floating MODUs (drillships and semisubmersibles) and some DP OSVs may be required to operate at "open bus-tie" versus "closed bus-tie" if determined to be the safest mode of operation, which would eliminate any NO_x reductions achieved via operational controls like an EPMS and more likely increase NO_x emissions.[9] Open bus ties are intended to provide increased redundancy into the functionality of dynamic positioning systems. This redundancy increases fuel consumption and requires more engines to operate at lower loads while a vessel is on station. These lower loads reduce engine load efficiency and increase NO_x emissions compared to operating fewer engines at higher loads. The EPMS or similar systems are designed to optimize engine loads on dynamically positioned vessels. On a drillship, this could entail operating two main engines at 40 to 65 percent loads rather than operating four main engines at 20 to 30 percent load. When large marine engines are operated at lower loads the NO_x emissions are significantly greater per kW of output and per time period.

Accordingly, any benefits from an EPMS type operational control are hypothetical at this time and not included in the net benefit calculation. The uncertain nature is due to both the Coast Guard's proposed rule which could prohibit operating with closed bus ties for DP-2 or DP-3 MODUs while drilling, and the fact that EPMS and similar systems are still being refined and tested. Nevertheless, we estimate that the MODU drilling NO_x reductions could range from 15 to 45 percent as a result of efficiencies from a closed-bus ties with EPMS.[10] At a benefit value of $5,000 per ton of NO_x (see Figure 7) reduced with a 15 percent reduction in NOx for DP MODUs in projects exceeding the SIL, this operational control could provide a benefit of $18 million.

Compliance Cost for Tier-3 SCR Engines or Engines Retrofitted with SCR

Requiring companies to use the "best available" control technology to reduce NO_x emissions can result in many scenarios. One alternative to reduce NO_x involves MODU category 3 engines retrofitted with a SCR unit or Tier-3 SCR marine engines to lower NO_x emissions below the SIL. This SCR emission reduction measure assumes that GOM DOCD plans are exceeding the SIL for NO_x in nonattainment areas.

SCR units are the most effective method to drastically reduce NOx emissions. This SCR ERM option considers the use of SCR units or Tier-3 marine engines with SCR technology. It is noted that while SCR units and Tier-3 engines are often the most effective in terms of NO_x reduction potential, they are not the only BACT options available. Statoil listed 17 different BACT options in their EPA application which are listed below[11]:

1. Exhaust Gas Recirculation
2. Ignition Timing Retard
3. Combustion Air Chiller/Intake Air Cooling
4. Water Injection
5. Fuel Water Emulsions

[9] If a generator or engine fails, the busses automatically "tie", or connect together so one generator continues to powers both.

[10] The potential of a maximum 45% NOx reduction is obtained from the EPA region 4 preliminary determination for an OCS permit in the eastern GOM. The potential NOx reductions are found in Table 6-1: Step 3 Control Technologies Ranked by Effectiveness http://www.epa.gov/region4/air/permits/ocspermits/shell/2011_08_19_Document_Shell_%20PrelimDeterm.pdf

6. Intake Air Humidification
7. Engine Re-Tooling (engine rebuild kits)
8. Derating the Engine
9. NOX Adsorber (NOX Traps)
10. Lean NO_x Catalyst or Hydrocarbon SCR
11. $CSNO_x$ Emissions Abatement System
12. Low NO_x Engine Design (LND)
13. Engine Replacement to meet higher EPA Tier standards (40 CFR part 89, 94, or 1042)
14. Selective Catalytic Reduction (SCR)
15. High Injection Pressure (HIP)
16. Turbocharger with Aftercooler
17. Good Combustion Practices (GCP)

This is not a complete list of available NO_x reduction technologies but it is illustrative. As new technologies become available and existing technologies become more cost effective, the list is likely to change. Most of these technologies were not considered to be technologically feasible at the time of the analysis.

SCR Retrofit – Main Engines Scenario

Relevant, but limited, cost data for SCR installations were available from the EPA's Region 4 OCS air permits in the eastern GOM. The BACT cost data were obtained from industry applications submitted to the EPA for OCS Air Permits pursuant to section 328 of the Clean Air Act. The most recent estimates available for retrofitting a mobile offshore drilling unit (MODU) with SCR units show the following costs[11]:

Table 7. SCR Installation and Operating Cost Estimates (Drillships)

Inputs	**Shell 2013 Noble Globetrotter**	**Anadarko 2013**	**Statoil 2014 DeSoto Canyon**
Amortization Period (years)	10		
Discount Rate	7%		
Total Capital Cost	$22,030,580	$22,563,011	$42,844,411
Annual Operating Cost	$10,569,488	$8,814,702	$6,182,547
Annual Amortized Capital Cost	$3,136,659	$3,212,465	$6,100,080
Total Annual Cost (TAC)	$13,706,147	$12,027,167	$12,282,627
Day Rate Premium (TAC/365)	**$37,551**	**$32,951**	**$33,651**

[11] OCS Air Permits from Shell, Anadarko, and Statoil were used and can be found on EPA's website: http://www.epa.gov/region4/air/permits/ocspermits/ocspermits.html

Offshore drilling companies charge operators a daily rate for each drilling rig, so the cost of adding SCR units were calculated as a day rate premium. Applying this day rate premium was the most realistic, uniform method available for each scenario. The total capital and operating costs were amortized over a 10-year period, which assumes the rigs will continue to be hired with the SCR equipment after these contracts end.

BOEM excluded from the capital costs the necessary expenditures required to prepare a GOM port to support SCR operations. SCR processes use large amounts of urea, a corrosive organic compound. Onshore stainless steel storage units are needed and on supply vessels to handle and transport this compound safely. Currently, GOM ports lack these capabilities. In requiring SCR, the one-time infrastructural costs are estimated to be about $5 million but are too uncertain to be included in this analysis.

The cost estimates in Table 7 are for drillships. The cost premium was slightly reduced for jackup and semisubmersible-MODUs since the technical difficulty of installing SCR units on these vessels may not be as complicated. The relevant costs used in the analysis are listed below in Table 8. Day rates and the SCR day rate premiums were rounded.

Table 8. Cost Inputs by Category (2014)

Cost Category	Cost
Jackup Unloaded Day Rate	$150,000
Semisubmersible Unloaded Day Rate	$470,000
Drillship Unloaded Day Rate	$550,000
BACT Jackup Day Rate Cost Increase (%)	2.5%
BACT Semisubmersible Day Rate Cost Increase (%)	1.9%
BACT Drillship Day Rate Cost Increase (%)	2.7%
BACT Jackup SCR Day Rate Cost Increase ($)	$7,500
BACT Semisubmersible SCR Day Rate Cost Increase ($)	$20,000
BACT Drillship SCR Day Rate Cost Increase($)	$30,000

Other Cost Factors: Vessel/Facility Size and the NO_x Reduction Target

The cost of retrofitting existing MODUs with SCR units can vary widely and may significantly differ from these cost estimates depending on the space or engineering limitations. An SCR unit is unique for each engine/stack. The unit SCR cost for a specific MODU is generally scalable for the number of engines. This analysis assumes 4 SCR units for jackups, 6 for semisubmersibles and 8 for drillships if all engines on a MODU were outfitted with SCR units.

The available space on a vessel is important because MODUs may not have enough space to properly install an SCR unit without significant modifications. However, if the MODU is smaller (i.e., jackup) and emits a relatively low volume of NO_x resulting in a lower reduction target, a less expensive SCR unit might be adequate or other options including engine replacement could be cost effective. At this time, there are insufficient data to provide a thorough analysis of how the costs associated with retrofitting MODUs with SCR units are expected to vary given the different types of MODUs and the corresponding NO_x reduction target in each scenario. These factors are expected to offset at least partially, but whether this results in a net positive or negative impact on the final cost will vary by project. This analysis assumes a standard cost and emissions schedule for each rig type included. BOEM seeks comments on the cost estimates and methodology for SCR and other ERMs potentially used on MODUs to prevent NO_x exceedance.

Tier-3 SCR Engine Scenario

Tier-3 category 3 engines provide an alternative to retrofitting existing Tier-0, Tier-1 or Tier-2 engines with SCR technology. Rather than install SCR equipment on category 3 engines, operators can comply with the regulations by contracting with MODUs that are equipped with Tier-3 SCR equipped engines. Tier-3 marine engines are those engines installed on new-build or retrofitted MODUs delivered in 2016 and later. The NO_x emission reductions for these engines are due to the post-combustion SCR technology that is designed and built into the MODU. Currently there are a few new 6th generation drillships scheduled to enter the GOM inventory with Tier-3 SCR capable engines.

Table 9 summarizes average relevant unloaded dayrate(s) for GOM drillships with different category 3 (>3,000 hp) Tier-engines. This day rate data is from late 2014.

Table 9. Day Rates for Tier-3 SCR Engine Scenario

Engine Tier	Unloaded Day Rate ($thousands/day)
0	$540
1	$542
2	$550
3	$599

These newest drillships are expected to be mobilized for ultra-deepwater projects more than 150 miles from shore. If utilized for deepwater projects less than 100 miles from shore to meet NOx reduction requirements, the incremental dayrate could be considered a compliance cost of this proposed rule. BOEM estimates that one-half of the differential day rate between Tier-2 and Tier-3 drillships is due to the added cost of the Tier-3 engines. The remaining day rate premium is for other efficiencies and capabilities on this newest generation of drillship.

BOEM's estimate for the incremental dayrate for Tier-3 capable engines is $24,500 [($599,000-$550,000) * 0.5 = $24,500]. BOEM welcomes comments on the costs and potential NOx reductions for Tier-3 capable MODUs.

A $24,500 incremental dayrate for drillships equipped with Tier-3 SCR capable engines is less than the $30,000 day rate premium estimated for drillships retrofitted with SCR technology. Additionally, since the Tier-3 SCR unit is designed and built into the stack, it is expected to operate with much greater efficiency and NOx reductions. Given cost differences between an engine retrofit on an existing MODU and a new Tier-3 engine built into a newly constructed MODU, operators may choose the lower-cost Tier-3 engine option.

BACT with Equipment Replacement

Engine replacement is an ERM option for plans exceeding the SIL in nonattainment areas. Engines efficiency may decline under routine, continual use, and newer engines may be less polluting than older ones. So, replacing older engines with newer equipment can result in NO_x reductions. In fact, replacing a Tier-0 marine engine with a Tier-2 engine may result in 50 percent or greater NO_x emission reductions.

Engine replacement is considered technically feasible though not necessarily cost effective. For example, consider Shell's 2011 air permit application to the EPA for the *Deepwater Nautilus* semi-submersible. The *Deepwater Nautilus* was built in 2000 and the main generator engines are Tier-0. The company estimated that replacing the four main generator engines with Tier-2 would provide NO_x reductions at a cost of approximately $80,000 per ton.[12] The EPA concurred with the company's analysis and concluded main engine replacement was not cost effective for the *Nautilus* and would not qualify as a cost-effective best available control technology.

As of early 2015, BOEM estimates that 75 percent of the GOM drillships, 30 percent of the GOM semisubmersibles, and 10 percent of the drilling or ready-stacked jackups are equipped with Tier-2 engines. Since drillships are the most common MODU in the GOM and 75 percent are already Tier-2, the potential cost-effective reductions are unlikely to be realized.

Emissions Reduction Credits

Emissions credits are a compliance alternative to SCR engine retrofits on category 3 engines, contracts for new MODUs with Tier-3 engines, and/or equipment replacement. While the price of NOx credits can vary widely, credits are assumed to be offsets that cost an average of $3,000 per ton of NO_x reduced in this analysis.

Under the proposed rule, emissions credits include emissions offsets and trading allowances. As defined in the proposed rule (§ 550.302), emissions credits are:

> *"…from an emissions source(s) not associated with the plan that are intended to compensate for the excessive emissions of criteria or precursor air pollutants, regardless of whether these emissions credits are acquired from an emissions source(s) located either offshore or onshore, including: (1) emissions offsets generated by a lessee or operator directly; or (2) emissions offsets acquired from a third party; or (3) trading*

[12] Source: http://www.epa.gov/region4/air/permits/ocspermits/shell/2011_08_19_Document_Shell_%20PrelimDeterm.pdf

allowances or other alternative emissions reduction method(s) or system(s) associated with a market-based trading mechanism; examples include mitigation banks or other competitive markets where these assets are exchanged."

Lessees with plans that exceed the SIL in nonattainment areas can choose to purchase emissions credits. Through the use of these credits, a project can achieve the same level of compliance that would otherwise require more expensive SCR engine retrofit or Tier-3 engines to reduce NOx emissions.

Offsets are an important component of emissions credits available to lessees. In general, offsets are regulated at the state level and used in various state air agency programs located in regions that exceed the EPA's National Ambient Air Quality Standards (NAAQS). For example, the Air Resources Board (ARB) of the California Environmental Protection Agency regulates the use of emissions reduction credit banking. Emissions credits can be generated from several methods (e.g., agricultural operations, via curtailing field burning or using water pumps with more efficient engines) and are subject to district rules and regulations.

In the state of Texas, the Texas Commission on Environmental Quality (TCEQ) is the regulatory agency tasked with protecting the state's public health and natural resources, including a clean air environment. To comply with various federal and state air regulations, the TCEQ offers various voluntary programs designed to reduce emissions, including the Discrete Emission Credit Program. This program allows participants to generate and sell credits by creating temporary emission reductions via installation of pollution control equipment, process changes, or investment in pollution prevention projects.

Prices for credits within the program have varied across time and space. For example, based on trades from 2000 to 2012, the price per ton of NOx reduced ranged from $70/ton to $14,000/ton in the Houston-Galveston-Brazoria area, with an average price of $1,645/ton[13]. The same reduction in the Dallas-Fort Worth area ranged from $1,710/ton to $25,000/ton, with an average price of $11,391/ton. More recently, in the first few months of 2014, credits for NOx traded between $5,000/ton and $10,000/ton for the Houston-Galveston-Brazoria area. Local supply and demand conditions drive the market variation for offsets, so there is no standard or uniform price for one ton of NOx emissions reduced. Significant variation can occur between counties within the same state, as well across states more broadly.

Emissions credits are included as a means of emissions reduction in recognition of the variety of ways a project can comply with the mitigation. Depending on the relative prices of other ERMs, these credits may or may not offer a less expensive compliance alternative. Given uncertainty in how future offsets will be offered and supplied to the market in each state, BOEM assumes an average offset price of $3,000 per ton of NO_x reduced. The credits scenario accounts for the uncertainty associated with the new exemption thresholds by applying the estimated costs and

[13] Discrete Emission Credit Banking and Trading Program Audit. *Texas Commission on Environmental Quality,* 2013.

benefits to a range of operating MODUs per year. BOEM seeks further comments on the price of offsets and their policy design in the proposed rulemaking.

Other Credit Reduction Methods

Emissions offsets purchased in a market are an important component of emissions reduction credits, however, lessees can achieve equivalent reductions through other means. Emission credits can be obtained from emissions source(s), either offshore or onshore, that affect the air quality of the same Air Quality Control Region (AQCR). For example, lessees may pay an onshore facility owner to reduce facility emissions as an alternative to purchasing offsets in a market. The lessee may own the onshore facility where the proposed reductions would occur.

The proposed rule at § 550.309(e)(4) provides that the operator "must also demonstrate that any emissions reductions will last for a period of time sufficient to ensure your plan's continued compliance with the provisions of this subpart." This provision should benefit plans near shore. BOEM expects that near-shore DOCDs projected emissions may often exceed the SILs for short periods when an operator mobilizes tug boats for Jack-up placement or removal, lift boats for construction or repairs, or mobilize other vessels for short durations. Under proposed § 550.309(e)(4) operators have the option to procure emissions credits for the same time period(s) in the same AQCR when the SIL or AAI is exceeded.

A lessee may also propose to reduce emissions on a separate OCS facility as long as the reductions benefit the same AQCR. This could include a lessee paying another operator to reduce OCS facility emissions. Operators would negotiate with one another to determine the appropriate payments required to induce emissions reductions and satisfy the criteria under proposed § 550.309 (e).

Either of these methods, whether onshore or offshore, would likely be less expensive than SCR retrofits, Tier-3/category 3 engines or equipment replacement. Additionally, reductions from these other methods may cost less than offsets. BOEM does not have any data or estimates on the nature of these transactions and seeks comments on the general use and requirements of these other emissions credit reduction methods.

NO_x Reductions Benefits

For the exploration and development plans that would require ERM for NOx emissions reduction, the onshore air quality would be improved over the existing baseline. It is very difficult to estimate and monetize benefits for NOx emissions reductions offshore because of the distance of OCS operations from onshore population centers.

BOEM's best benefit estimate for OCS NOx reductions is obtained from the BOEM Offshore Environmental Cost Model (OECM). The OECM is primarily used to estimate the social and environmental costs for projected OCS exploration and development activity.[14] The OECM includes an air quality module that estimates the monetary value of the environmental damage caused by these air pollutants including NOx (estimated on a dollar-per-ton basis). The OECM dollar-per-ton values are derived from a modified version of the Air Pollution Emission Experiments and Policy analysis (APEEP) model[15] which follows a three-step analytic chain:

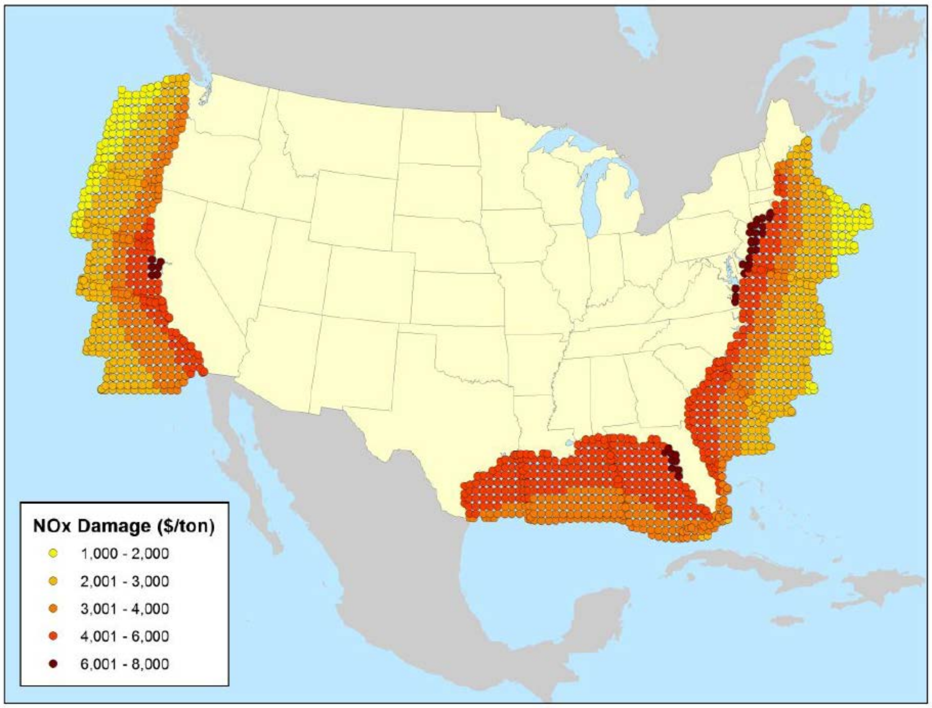
1. Air Quality: The APEEP model estimates the extent to which one ton of emissions of a given pollutant affects ambient pollutant concentrations in different locations.
2. Physical Effects: Based on the change in air quality estimated for each location, APEEP employs a series of peer-reviewed dose-response functions to estimate changes in the incidence of various adverse physical effects (e.g., premature mortality).
3. Valuation: APEEP estimates the monetized value of the change in physical effects based on information from the economics literature and other published sources.

According to the model, polluting sources closer to land cause greater damage per ton than sources farther from shore. Sources located near large cities tend to cause greater damage than sources offshore from rural areas, and the importance of prevailing winds is clearly evident. The estimated offshore NOx damages on a $/ton basis are shown in the following map from OECM (Figure 7).

[14] BOEM OCS Study 2012-025 Forecasting Environmental and Social Externalities Associated with OCS Oil and Gas Development: The Revised Offshore Environmental Cost Model http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Leasing/Five_Year_Program/2012-2017_Five_Year_Program/OECM.pdf

[15] APEEP model developed and maintained by Nick Muller: https://sites.google.com/site/nickmullershomepage/home/ap2-apeep-model-2.

Figure 7. Estimated Damages Due to NOx Emissions (OECM Model)



Most of the short-term GOM exploration and development plans (3 years or less in duration) requiring ERMs are expected to occur in the areas associated with damages of $4,001 to $6,000 per ton. The larger long-term development plans with two MODUs drilling concurrently and requiring ERMs are also expected to occur in the areas associated with damages of $4,001 to $6,000 per ton. These larger plans are most likely to be in the Mississippi Canyon area and less than 100 miles from shore. The benefit value selected for the analysis of the exploration and development plans was $5,000/ton of NO_x reduction, the mid-point of the relevant benefit range used in the OECM for most of the GOM. These values were applied to the total BACT NOx reductions estimated from the representative exploration and development plans.

Computing the NOx emissions reduction involved 3 steps, with relevant inputs shown in Table 10:

1. The average NO_x emissions were calculated for each type of MODU expected to be used each year. NOx emissions totals for rig type were provided by the BSEE Gulf of Mexico region.
2. The NOx emissions were reduced by 50 percent, which is the amount of NOx emissions SCR units installed on MODUs can remove on average, though many units can achieve greater than 90 percent reductions under ideal conditions such as the Tier-3 new-build marine category 3 engines.
3. The final value of NOx reductions in tons was multiplied by $5,000 for exploration and development plans requiring SCR BACT, resulting in the total annual benefit applied to each year.

Table 10. Key Parameters for Benefits Calculation

Key Benefit Inputs	**Value**
Jackup NOx Emissions (tpy)	397
Semisubmersible NOx Emissions (tpy)	800
Drillship NOx Emissions (tpy)	3,130
Benefit/ton of NOx all Plan Types ($)	$5,000
BACT Emissions Reduction Factor	0.50

BSEE engineers provided NO_x emissions estimates for each type of drilling rig and the results are shown in Table 11. The estimates are based on the following assumptions:

- Actual rated MODU Prime Mover engines. This information was obtained from the MODU specification data sheet from various vendors. Some information was found in BOEM approved DOCDs and/or APDs.
    - The Drillship prime movers engines range from 26120 to 43740 kw with six or eight main engines.
    - Jackup prime engines range from 2575 to 9150 kw typically with four main engines.
- Actual number of days of drilling. The time (days) was checked in GOADS and e-Well data base for 2011.
- The emission factor used for emission estimations was 19.54 grams/kw-hr for from the GOADS 2011 inventory.
- The engine load factor used in these estimates was 75 percent from GOADS 2011; however, load factors less than 75 percent are frequently observed in some DOCDS and APDs.
- The NOx annual emission estimates were calculated using rig type main engine power specifications, actual days of scheduled operations, engine load factor and NOx emission factor as used in the 2011 GOADS emission inventory.

Table 11. NOx Emissions Calculations by Rig Type

Rig Type	**Average Days**	**Average Hours**	**Average KW**	**NOx Emissions (tons/year)**
Drillship	202	4,848	39,960	3,130
Semisubmersible	208	4,992	9,916	800
Jackup	191	4,584	5,348	397

Net Benefit for ERM (GOM)

Operators have the option to purchase emissions credits within the affected onshore air quality compliance region to offset OCS emissions. If equivalent NOx credits are purchased, BOEM estimates that the reductions can be achieved more economically than SCR BACT. Consistent with $3,000 estimated cost per ton described in the *Emissions Reduction Credits* section and the $5,000 benefit from reducing a ton of NOx in the *NOx Reductions Benefits* section and the

MODUs requiring significant NOx reductions (Figure 4), Table 12 summarizes the annual costs, benefits and net benefits.

Table 12. Estimated Net Benefit for Emission Credits - Projects above the SILs (Nonattainment areas)

MM$ Years →	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Cost at $3,000/tpy NOx	$15.9	$21.2	$25.9	$25.9	$20.6	$11.2	$5.3	$4.7	$0.0	$0.0
Benefit at $5,000/tpy NOx	$26.5	$35.3	$43.1	$43.1	$34.3	$18.6	$8.8	$7.8	$0.0	$0.0
Net Benefit:	**$10.6**	**$14.1**	**$17.2**	**$17.2**	**$13.7**	**$7.5**	**$3.5**	**$3.1**	**$0.0**	**$0.0**

Monitoring

The proposed rule would make a number of changes to the requirements for reporting, tracking and monitoring of the air emissions. These proposed monitoring requirements are found in sections § 550.311 and § 550.312. Consistent with current regulations, operators would provide a description of proposed ERMs, emissions reduction control efficiencies, the projected quantity of reductions and the type of monitoring system proposed. The proposed rule requires emission monitoring for plans or emissions sources meeting a certain criteria. Monitoring systems must account for emissions from every source in the approved plan and must reflect actual OCS operations. In order to demonstrate compliance with an approved plan the operator must maintain records of fuel consumption, fuel type and activity information for each emissions source.

The monitoring costs for this proposed rule are modest because it is assumed that *actual* emissions will not be measured except for specific limited circumstances. The most costly requirement is to collect fuel and activity data on a plan basis (§ 550.312) and not just on a complex basis (§ 550.187).[16] The type of emissions monitoring depends on the BOEM imposed conditions in plan approval. Some monitoring requirements in the proposed rule are prescriptive; others may be required at the discretion of the Regional Supervisor.

Table 13 summarizes BOEM's best estimate of both the prescriptive requirements and the instances when the Regional Supervisor will exercise his/her discretion to require emissions monitoring.

Table 13. Proposed Rule Monitoring Requirements

Provision	Assumed Impact
Recordkeeping Each Source all Plans (Fuel/Activity)	At a minimum, all sources will continue to maintain and report fuel use or activity levels.
Reporting Fuel/Activity (~1/3 plans)	Per § 550.312 of the proposed rule, activity and fuel

[16] The monitoring requirements in Subpart A are not new and have been a current practice for the GOM area where DOI has air quality jurisdiction.

	data for an approved plan must be retained by the operator for 10 years. Section 550.312(b)(1) states that operators must "submit this information to BOEM on a schedule set by the Regional Director." This analysis assumes the Regional Directors will require annual reporting of the monthly data for all plans required to model or employing emission reduction measures. This requirement is estimated to apply to about one-third of plans approved each year.
Stack Testing (avg 67/yr)	While not required directly by the regulation, it is assumed that operators will request that contractors perform stack tests on selected MODU's to ensure that they have an accurate estimate of emissions.
PEMs Monitoring (uncertified Engines) [assume 3 new/yr in GOM]	Engines that are built to export specifications but are nonetheless installed domestically will need actual emissions monitoring

In addition, it is possible that if an emissions credit scheme is implemented, then PEMs monitoring may be required by the Regional Supervisor to obtain accurate measurements of actual emissions. However, this option is not included in the cost estimates.

In the proposed rule, BOEM solicits comment on whether there are other ways of collecting information or monitoring to ensure ongoing compliance with approved plans. For purposes of this RIA, BOEM is interested in specific comments about the cost of any alternatives to this requirement and how they would minimize the data collection and reporting burden associated with fuel logs. BOEM also welcomes comments on monitoring costs when offsets or emission credits are used.

Monitoring Compliance Cost Summary

Table 14 summarizes the Subpart C estimated monitoring costs. The following sections provide additional detail on the cost assumptions.

Table 14. Ten-Year Estimated Monitoring Costs

Monitoring Costs $millions	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Recordkeeping Each Source all Plans (Fuel/Activity)	$1.1	$2.2	$3.2	$4.0	$4.8	$5.5	$6.1	$6.7	$7.2	$7.7
Reporting Fuel/ Activity (~1/3 plans)	$0.1	$0.2	$0.4	$0.4	$0.5	$0.6	$0.7	$0.7	$0.8	$0.9
Stack Testing (avg 67/yr)	$1.7	$1.7	$1.7	$1.7	$1.7	$1.7	$1.7	$1.7	$1.7	$1.7
PEMs Monitoring	$0.1	$0.2	$0.2	$0.3	$0.4	$0.5	$0.5	$0.6	$0.7	$0.8

(uncertified Engines) [assume 3 new/yr in GOM]										
Total:	$3.0	$4.3	$5.4	$6.5	$7.4	$8.3	$9.0	$9.8	$10.4	$11.0

Monitoring: Fuel logs and Activity Data

Proposed § 550.311 and § 550.312 describe the monitoring requirements that would apply to demonstrate compliance with an approved plan. Under the proposed rule all operators would be required to retain information on monthly fuel consumption and activity for every emissions source, including attributed emissions sources, showing the quantity, and type of fuel used. Operators would report these data along with calculated emissions on a schedule established by the Regional Supervisor. BOEM assumes in most cases the Regional Supervisor will require the reporting of monthly data on an annual basis for those plans that exceed the exemption threshold or employ ERMs.

Stack Testing: § 550.312(a)

If stack testing is used as a method to develop the emissions factors, then the operator must conduct stack testing every three years and report the results. This provision is consistent with BOEM's current regulatory requirements. BOEM expects that an increased number of plans will employ stack testing to confirm the use of alternative emission factors for engines under this proposed rule. This increase is driven by the same factors increasing the number of plans required to conduct modeling, including: the required consolidation of plans, movement to a rolling 12-month average, elimination of the 25-mile rule, and the movement of the compliance determination line or location to the federal/state submerged lands boundary.

Offshore stack testing costs about $30,000 per test for a single stack test. BOEM assumes testing efficiencies will be realized for multiple stack tests and the average cost per stack test will cost about $25,000.

BOEM expects the proposed rule will cause operating companies to require stack test data less than 3 years old to be available as a condition of leasing most MODUs. BOEM expects to review recycled MODU engine stack test results in multiple plans. This analysis assumes BOEM will follow the EPA practice which allows an operator to infer stack testing results from two engines to all identical engines on a project. For example, if there are six identical main engines on a drillship, stack test results for only two of the six engines would be required. The resulting emission factors would be applied to the remaining four main engines.

For this analysis, BOEM assumes a static population of MODUs available for drilling in OCS waters over the next 10 years. This analysis includes 10 jackups, 10 semisubmersibles and 30 drillships. The jackup and semisubmersible MODUs would receive two stack tests per MODU each three years. The drillships would each be subject to four stack tests to cover the two main engine types typical on drillships each three years. If the MODU stack tests are spread evenly over the three-year period, there would be about 53 MODU engine stack tests each year.

The proposed rule will cause some operators to opt for stack testing on larger natural gas turbines or engines on production facilities. BOEM estimates that this could include about 21 production platforms conducting stack testing for 2 natural gas turbines or engines each. Spread evenly over three years, this will result in in about 14 engines stack tested on production facilities each year.

The proposed rule will likely cause about 67 new stack tests each year for OCS engines. At a cost of $25,000 per stack test, the annual compliance cost is about $1,675,000.

Methods to Monitor Actual Emissions

The two standard practices for monitoring actual emissions are Continuous Emissions Monitoring Systems (CEMS) and Parametric Emission Monitoring Systems (PEMS). Both of these methods are more expensive and require greater crew monitoring efforts than the proposed monitoring requirements for fuel consumption and activity in § 550.312. While the monitoring of actual emissions is likely to be more accurate than calculating emissions through emissions factors and fuel consumption, BOEM does not have a basis at this time to estimate the accuracy improvement for CEMS and PEMS compared to the current standard practice.

CEMS

A continuous emission monitoring system(s) (CEMS) is an integrated system that demonstrates source compliance by collecting samples directly from the stack discharging pollutants. A CEMS unit consists of all the equipment necessary for the determination of a gas or particulate matter concentration or emission rate. This includes three basic components:

1) The sampling and conditioning system,
2) The gas analyzers and/or monitors, and
3) Data acquisition system (DAS) and controller system.

A CEMS can be designed to monitor a single pollutant or multiple pollutants and waste gas stream parameters.

Monitoring and maintenance for CEMS would likely require a full-time worker or a significant share of time for a part-time worker. The probes must be cleaned, checked and maintained and sampling conducted to ensure continued accurate readings. For these reasons, this analysis does not assume a CEMS system for estimating the regulatory compliance costs for those plans that must report actual plan emissions to BOEM.

PEMS

PEMs is a more flexible and cost-effective alternative to continuous instrumental emissions monitoring. Parametric monitoring differs from CEMS in that emissions are not directly measured. Parametric monitoring is the monitoring of key, emissions-correlated parameters (e.g., pressure, temperature and flow rate). PEMS can be designed to predict emissions of nitrogen oxides (NOx), carbon monoxide (CO), total hydrocarbons (THCs), oxygen (O2), and carbon dioxide (CO2).

The PEMS approach to monitoring exhaust emissions is based upon establishing relationships between engine operating parameters, as determined by commonly used engine sensors, and exhaust emissions. A separate PEMs system would be installed for each engine being measured, although there are opportunities to share computer processing equipment when multiple PEMs are installed. The PEMs operating parameters are monitored by thermocouples, differential pressure gauges, or other instrumentation as opposed to ultra-sensitive probes that measure emissions directly. PEMS are fundamentally computerized algorithms that describe the relationships between operating parameters and emission rates and which estimate emissions without the use of continuous emission monitoring systems. Advantages to the PEMS approach to monitoring over CEMS applications include eliminating costs associated with monitoring instrumentation and the cost of maintaining the sampling and analysis systems, and procurement of analyzer calibration gases.

Each engine produces unique relationships between emissions and engine operational functions, so initial parameterization of a PEMS must be engine specific. Engine and emission relationships can be a function of engine speed and engine load. Other operational parameters could include: engine efficiency (calculated fuel consumption/actual fuel consumption), ignition timing, combustion air manifold temperature, and combustion air manifold pressure.

PEMs Cost and Installation Challenges

Limited cost information is available for the installation of PEMs on OCS facilities and vessels. The PEMs installation cost on OSVs, MODUs or production facilities are much higher than installation of PEMs for onshore facilities. There are a few cost drivers specific to PEMs systems that increase the cost relative to onshore facilities.

One of the primary cost drivers is the necessity for a climate controlled measurement room. The PEMs measurement equipment and computer size create challenges on smaller vessels and even on larger vessels may necessitate partitioning of existing storage space to free up space to provide air conditioning to the PEMS. In addition to the space challenges on vessels, there is the concern of cutting through bulkheads to install the wiring, piping or cabling to install the system. On a large vessel like a drillship there can be many thousands of feet of stainless steel piping required for the emissions measurements.

PEMs Monitoring Assumptions

The proposed rule requirements at § 550.311(b) state: "Your measurement of actual emissions must include enough of your emissions sources to ensure that the actual emissions associated with facilities and MSCs operating under your approved plan are consistent with the projected emissions approved for your plan. You must consider every source that was included in your approved plan in addition to any source that would be classified as part of your projected emissions if your plan were resubmitted under the current regulations." BOEM uses uncertain but the best available estimates regarding the number of engines in approved plans that must demonstrate actual emissions under § 550.311(a).

BOEM analysis assumes about 3 non-certified engines each year may require the monitoring of actual emissions. BOEM does not know how many non-certified engines may be on the OCS but believes the number is very small. There are two primary ways a non-certified engine may be on a MODU or OCS platform. The first is that a MODU while drilling overseas may have installed or replaced an engine with a non-certified engine. The second is that an operator may have installed a non-certified engine in violation of violation of EPA regulations. The proposed provisions in § 550.311 require the monitoring of actual emissions for non-certified engines or the largest emission sources for plans employing certain ERMs.

Proposed Rule Compliance Cost Summary

The proposed rule's compliance costs partially derive from, and are mostly consistent with, the information collection (IC) burden estimates. Table 15 is a modified version of the Paperwork Reduction Act (PRA) table in the rule preamble to show BOEM's compliance cost estimates for this proposed rule. As shown in the third column of the first two rows, BOEM estimates that over the next decade up to 110 EPs and 235 DOCDs will receive annual air quality reviews. The quantity of annual responses derives from historical BOEM plan reviews and the estimated number of plans that will be required to meet the proposed requirements. Table 15 shows the first year (Year 1) and full period (10-Year) compliance cost estimates.

Table 15. Estimated Proposed Rule Compliance Cost

550 Subpart B	Reporting and Recordkeeping Requirement	Hrs.	Avg # of Annual Responses	Year 1 Cost	10-Year Cost (nominal$)	10-Year Cost (3%)	10-Year Cost (7%)
Contents of Exploration Plans							
New 205	Collect, maintain & submit all air quality & modeling documentation.	20	varies by year	$198,400	$2,579,200	$2,185,358	$1,782,934
	Submit expanded air emissions & compliance data for EPs whose air emissions are above the exemption threshold.	25	20	$62,000	$620,000	$528,873	$435,462
	Subtotal			**$260,400**	**$3,199,200**	**$2,714,231**	**$2,218,396**
Contents of DPP and DOCD							
New 205	Collect, maintain & submit all air quality & modeling documentation.	20	varies by year	$289,154	$3,634,458	$3,080,364	$2,514,249
	Submit expanded air emissions & compliance data for DPPs/DOCDs whose air emissions are above the exemption threshold.	25	50	$155,000	$1,550,000	$1,322,181	$1,088,655
Subtotal				**$444,154**	**$5,184,458**	**$4,402,546**	**$3,602,904**
Total Subpart B				**$704,554**	**$8,383,658**	**$7,116,777**	**$5,821,300**

550 Subpart C	Reporting and Recordkeeping Requirement	Hrs.	Avg # of Annual Responses	Year 1 Cost	10-Year Cost (nominal$)	10-Year Cost (3%)	10-Year Cost (7%)
Air Quality Analyses in Plans							
New 303-307	Conduct required analysis & modeling for expanded air emissions for all criteria & major precursor air pollutants & compliance. Submit modeling reports.	38	87	$409,944	$4,099,440	$3,496,905	$2,879,275
		$10,000	20	$200,000	$2,000,000	$1,706,041	$1,404,716
		$20,000	varies by year	$700,000	$13,480,000	$11,268,947	$9,026,208
		$50,000	varies by year	$0	$70,000,000	$57,015,915	$43,992,655
New 303(d)	Report air emissions data from multiple facilities if required.	20	15	$37,200	$372,000	$317,324	$261,277
New 303(h)	Provide add'l information/analysis as required for plan approval.	10	300	$372,000	$3,720,000	$3,173,235	$2,612,772
New 304	Obtain approval of modeling protocol & meteorological data set.	5	4	$2,480	$24,800	$21,155	$17,418
Subtotal				**$1,721,624**	**$93,696,240**	**$76,999,522**	**$60,194,323**
550 Subpart C	**Reporting and Recordkeeping Requirement**	**Hrs**	**Avg # of Annual Responses**	**Year 1 Cost**	**10-Year Cost (nominal$)**	**10-Year Cost (3%)**	**10-Year Cost (7%)**
Emission Reduction Measures Analysis after Modeling							
New 306; 307; 308(a); 309(a), (c), (d)	Document results of ERM analysis.	$200,000	varies by year (7 to 15/yr)	$1,400,000	$25,600,000	$21,436,378	$17,209,786
NEW 307(b); 309(e)	Control of emissions of criteria air pollutants from a long-term facility through Purchase of ERM emission credits	$3,000	varies per year	$15,880,500	$130,530,000	$117,150,543	$102,331,177
New 307(a); 313(a)	Request VOCs and No_x waiver for ERM	1	1	$124	$1,240	$1,058	$871
New 309(b)	Immediately, notify BOEM if ERM become disabled or unavailable; request extension for ERM	2	2	$496	$4,960	$4,231	$3,484

	(NTE 90 days).						
New 309(d)	Collect and maintain monthly logs of relevant meter/monitoring equipment readings	12	6	$8,928	$89,280	$76,158	$62,707
New 309(e)	Notify appropriate State air quality control jurisdiction of proposal to acquire emissions offsets.	1	1	$124	$1,240	$1,058	$871
New 310(b)	Request a departure from compliance with the new or revised ambient air standard.	2	2	$496	$4,960	$4,231	$3,484
New 310(c)	Resubmit plans for air quality review every 10 years	120	varies by year	$0	$1,562,400	$1,272,595	$981,916
		Subtotal		**$17,290,668**	**$157,794,080**	**$139,946,252**	**$120,594,295**

550 Subpart C	Reporting and Recordkeeping Requirement	Hour Burden	Avg # of Annual Responses	Year 1 Cost	10-Year Cost (nominal$)	10-Year Cost (3%)	10-Year Cost (7%)
	Monitoring & Reporting						
New 311(a), (f)	Report actual emissions data to verify compliance with previous approved plan on BOEM approved schedule - EP	16	varies by year	$126,159	$5,407,501	$4,445,190	$3,482,310
New 311(a), (f)	Report actual emissions data to verify compliance with previous approved plan on BOEM approved schedule - DOCD	16	varies by year				
New 311(c)	Measure actual emissions using Parametric Emission Monitoring System (PEMS).	$26,000	varies by year	$78,000	$4,290,000	$3,497,441	$2,709,652
New 311(d)	Report data/information regarding exceedance of projected emissions to BOEM	16	5	$9,920	$99,200	$84,620	$69,674
New 311(e); 312(a); 313(b); (d)(2)	Submit additional information as required to BOEM.	2	10	$2,480	$24,800	$21,155	$17,418
New 312(a)	Conduct/report stack testing results every 3 yrs. [tests]	8	67	$66,464	$664,640	$566,951	$466,815
		$25,000	67	$1,675,000	$16,750,000	$14,288,090	$11,764,499
New 312(b)	Retain monthly fuel information for each source on determined schedule for 10 yrs.	48	varies by year	$1,135,430	$48,667,505	$40,006,709	$31,340,786
New 312(b)	Submit fuel logs for facility and equipment usage information and MSCs to BOEM	8	varies by year	$63,079	$2,805,759	$2,298,499	$1,793,011
New 312(c), (d)	Collect/report meteorological data in a manner described by BOEM or from agreed location;	4	3	$1,488	$14,880	$12,693	$10,451

	other information as required.						
New 313(b)	Submit new air quality plan for short-term facility converted to a long term facility.	10	2	$2,480	$24,800	$21,155	$17,418
New 313(b)	Request exception due to adverse weather conditions or circumstances beyond your control.	0.5	4	$248	$2,480	$2,115	$1,742
New 314	Provide pollution data to State, Indian Tribe, or Federal agency.	2	2	$496	$4,960	$4,231	$3,484
		Subtotal		**$3,161,245**	**$78,756,524**	**$65,248,849**	**$51,677,261**
General							
New 300-314	General departure and alternative compliance/requests.	2	5	$1,240	$12,400	$10,577	$8,709
		Total for Subpart C		**$22,174,777**	**$330,259,244**	**$282,205,200**	**$232,474,587**
550 Subpart J	**Reporting and Recordkeeping Requirement**	**Hrs**	**Avg # of Annual Responses**	**Year 1 Cost**	**10-Year Cost (nominal$)**	**10-Year Cost (3%)**	**10-Year Cost (7%)**
1012	Collect, maintain & submit all air quality documentation/records pertaining to ROW applications; obtain approvals.	2	252	$62,496	$624,960	$533,104	$438,946
		Total for Subpart J		**$62,496**	**$624,960**	**$533,104**	**$438,946**
		Total Compliance Cost:		**$22,941,826**	**$339,267,861**	**$289,855,080**	**$238,734,833**

Regulated Entity Compliance Cost

As shown on the last row of Table 15, BOEM estimates the total industry compliance cost for operators to be $23 million in the first year and $339 million over 10 years. Discounted at 3 percent, the present value of projected compliance cost expenditures over this 10-year period is about $290 million. The peak year is 2020 where the annual costs are estimated to be $49.4 million.

BOEM does not expect that the proposed regulatory changes will be unduly burdensome to industry. The proposed requirements are intended to improve BOEM's review and approval of planned operations by requiring more accurate information and better assessments of the air quality impacts from OCS oil and gas operations. While many of the proposed regulatory changes require additional information from operators, the changes are not expected to increase the incidences of mechanical BACT on OCS facilities. BOEM expects that an increased percentage of plans will employ ERMs and emissions credits as a response to failing to meet exemption thresholds. Mechanical BACT emission controls or other ERMs may be required for some projects due to the proposed requirements in this rulemaking if emissions credits are not available. Other exploration or development projects may require ERMs due to changes in the EPA 1-hour NOx standard or changes to the ozone standard.

BOEM/BSEE Staffing

The additional air quality information required under this proposed regulation requires additional BOEM and BSEE staff. BOEM and BSEE are unlikely to be able to meet the additional burden with existing staff capacity. BOEM will primarily require staff to review and validate the information submitted with the plans, although this effort could be reduced when the e-Plans module is deployed. Minor BOEM effort will be required to receive and record the actual activity from mitigated plans. BSEE requires additional staffing to review or monitor BACT, stack tests, review monitoring data, and take compliance actions if necessary. In total by 2020, BOEM estimates 8 additional full-time equivalent (FTE) will be required in the GOMR and 4 additional FTE in the BSEE GOM Region. In total, the additional government compliance effort is estimated to require 12 FTE and cost approximately $1.6 million annually. Over 10 years discounted at 3 percent, the government compliance cost is estimated to be $12.1 million.

Consolidated Compliance Cost Summary

As shown in Table 16, BOEM estimates the total first year compliance cost for both the regulated industry and the government is $23.6 million and over 10 years is $302 million discounted at 3 percent.

Table 16. Industry and Government Consolidated Compliance Cost

MM$	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	TOTAL
Nominal	$23.6	$30.9	$37.2	$51.0	$46.8	$38.2	$33.2	$33.3	$29.3	$30.1	**$354**
3%	$22.9	$29.2	$34.1	$45.4	$40.3	$32.0	$27.0	$26.3	$22.5	$22.4	**$302**
7%	$22.1	$27.0	$30.4	$38.9	$33.3	$25.5	$20.6	$19.4	$15.9	$15.3	**$249**

Compliance Cost Estimate for Years 11-20

The analysis covers 10 years (2017 through 2026) to ensure it captures important costs that result from the proposed rule. A 10-year period was used for this analysis because of the uncertainty associated with predicting industry's activities, technological innovation and future air quality standards. Extrapolating results beyond a 10-year time frame will produce more ambiguous results and, therefore, be disadvantageous in determining actual costs and benefits likely to result from this rule. BOEM concluded that a 10-year analysis provides the best overall ability to reasonably forecast estimated costs and benefits likely to result from this rule.

However to provide stakeholders an insight on costs beyond 10 years BOEM estimates that the compliances costs would be relatively flat (see Table 17). These estimates are highly uncertain. Costs could be lower if OCS activity declines or technological innovation occurs. Costs could be higher if OCS activity increases or air quality standards are tightened.

Table 17 Years 11 to 20 Estimated Compliance Csots

Millions $	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	TOTAL
Nominal	$28.4	$28.4	$28.4	$28.4	$28.4	$28.4	$28.4	$28.4	$28.4	$28.4	$284.5
0.03	$20.6	$20.0	$19.4	$18.8	$18.3	$17.7	$17.2	$16.7	$16.2	$15.8	$180.6
0.07	$13.5	$12.6	$11.8	$11.0	$10.3	$9.6	$9.0	$8.4	$7.9	$7.4	$101.6

Alaska Arctic Baseline Analysis and Compliance Cost

The number and type of vessels required for Arctic oil and gas activities and the air pollutant emissions for an Alaska Arctic EP are expected to be greater than for a GOM EP, even considering the shorter drilling season (conducted only during ice-free periods). This resulting difference between expected emissions in the two regions exists under both the baseline and proposed rule. The following air emissions modeling and emissions reduction measures (ERM) cost estimates for exploration projects on the Arctic OCS show the likelihood that ERMs would be required in different areas of the Arctic. BOEM does not assign these Arctic regulatory compliance costs to the rule because operators incur these compliance costs under both the baseline and proposed rule.

Alaska Arctic Background

BOEM expects Arctic OCS plans and corresponding vessel emissions to be roughly the same in the Chukchi Sea and Beaufort Sea OCS Planning Areas because of similar operating environments. The primary differences between drilling activities in the Chukchi Sea OCS Planning Area and the Beaufort Sea OCS Planning Area is that Chukchi Sea lease blocks are in 30 to 40 meters of water and are at least 60 statute miles from shore, whereas the lease blocks in the Beaufort Sea are closer to shore and in shallower water.[17] The deeper water promotes use of MODUs, including drillships, that engage propulsion engines for Dynamic Positioning during drilling but which also increase emission rates. The shallower water (6 to 9 meters) on near-

[17] All Chukchi Sea OCS EPs, operating at a distance of at least 62 statute miles would likely to be exempt from emission-source controls and air dispersion modeling under the current regulations (30 CFR Part 550 subpart C). The current Five Year Program restricts leasing in the Chukchi Sea OCS Planning Area to acreage beyond 25 miles from shore. The closest point for an existing Chukchi lease is 61 statute miles from shore. BOEM expects most future proposed plans in the Chukchi Sea OCS Planning Area to be greater than 60 miles from shore. Given the anticipated distance from shore for Chukchi EPs, they are exempt from additional controls under the emission exemption equations (30 CFR 550.303(d)). BOEM expects a similar result for Chukchi DPPs.

shore lease blocks in the Beaufort Sea promotes the use of jack-up rigs rather than drillships which are towed to the drilling position and do not have propulsion engines.

In either case, the potential air quality impact of offshore emissions decreases with distance from shore, so that even with higher emission rates, the EPs and DPPs proposed for the Chukchi Sea lease blocks have less potential to cause significant air quality impact at the Alaska seaward boundary. The 78 leases in the Beaufort Sea range from 3 to 32 miles offshore. The most highly prospective exploratory drill sites on existing Beaufort Sea leases are less than 20 miles from shore. BOEM assumes that the four most likely Beaufort Sea exploratory prospects to be drilled range from 7.5 to 18 statute miles from shore. Even though the emissions are less for jack-up rigs, because the Beaufort Sea lease blocks are closer to land (most less than 30 statute miles), the EPs and DPPs proposed for the Beaufort Sea lease blocks have greater potential to cause significant air quality impacts at the Alaska seaward boundary .

Table 18 summarizes the projected emissions for criteria and precursor pollutants and exemption equation solutions resulting from hypothetical Chukchi Sea and Beaufort Sea OCS EPs using the estimated air emissions from Shell's 2013 Chukchi EP. "Yes" and "No" identify whether modeling or BACT is required. The data in Table 18 show which EP scenarios in each OCS Planning Area will most likely be exempt and those that would most likely exceed the exemption thresholds. These results are expected to be the same under both the baseline and proposed rule.

The data in Table 18 also show that for the Beaufort Sea EPs and DPPs proposing uncontrolled emission sources, NOx emissions would be non-exempt at both 7.5 statute miles and 20 statute miles. In order to be exempt, the drilling site would need to be at least 61 statute miles from shore for the uncontrolled NOx emissions, and no leasing beyond 60 miles is expected in the Beaufort. The drilling site would need to be at least 15 miles from the seaward boundary for controlled emission sources of NOx to be exempt from air dispersion modeling of onshore impacts. For the near-shore Beaufort Sea lease blocks (7.5 statute miles), emissions of volatile organic compounds (VOC) would also be non-exempt. Emissions of CO, PM, and SO_2 are low enough that no air dispersion modeling or mandatory controls are required for these pollutants.

Table 18. 2013 Withdrawn Chukchi EP, Maximum Projected Seasonal Emissions

Distance from Shore (in statute miles [sm]), and Projected Emission Scenarios	POLLUTANTS				
	PM[1] Particulate Matter	SO_2 Sulfur Dioxide	NO_x Nitrogen Oxides	VOC Volatile Organic Compounds	CO Carbon Monoxide
	Exemption Threshold Equations 30 CFR 550.303(d)				
	E=33.3xD				$E=3400x(D^{2,3})$
	Calculated Annual Emission Exemption Thresholds Based on Distance from Shore				
7.5 sm (min distance for Beaufort Sea prospects)	249.8	249.8	249.8	249.8	13,027.3
20 sm (max distance for Beaufort Sea prospects)	666.0	666.0	666.0	666.0	25,051.4
61 sm (min distance for Chukchi Sea prospects)	2,031.3	2,031.3	2,031.3	2,031.3	52,686.4
	Projected Emission Rates per Scenario and Exemption Status (in short tons per year)				
Uncontrolled Emissions [2]	63	104	2,019	415	1,357
Exempt at 7.5 sm (Beaufort Sea leases)?	Yes	Yes	***No***	***No***	Yes
Exempt at 20 sm (Beaufort Sea leases)?	Yes	Yes	***No***	Yes	Yes
Exempt at 61 sm (Chukchi Sea leases)?	Yes	Yes	Yes	Yes	Yes
Controlled Emissions [3]	23	47	467	149	300
Exempt at 7.5 sm (Beaufort Sea leases)?	Yes	Yes	***No***	Yes	Yes
Exempt at 20 sm (Beaufort Sea leases)?	Yes	Yes	Yes	Yes	Yes
Exempt at 61 sm (Chukchi Sea leases)?	Yes	Yes	Yes	Yes	Yes

[1] PM includes the emissions of PM_{10} plus $PM_{2.5}$.

[2] Shell Revised OCS Lease Exploration Plan, Chukchi Sea, Revision 2 November 2013. Appendix O, Table 7 *AQRP Seasonal Uncontrolled Emissions by Group* (Annual Emissions Total). Reflects the Air Quality Regulatory Program (AQRP) projection of uncontrolled emissions.

[3] Shell Revised OCS Lease Exploration Plan, Chukchi Sea, Revision 2 November 2013. Appendix O, Table 9 *Maximum Projected Seasonal Emissions by Group* (Annual Emissions Total). Reflects projection of controlled emissions used for the air quality analysis prepared under the National Environmental Policy Act (NEPA).

Arctic Modeling Costs

BOEM assumes that activities described in plans for Chukchi OCS projects would not require air dispersion modeling or emissions controls. However, BOEM assumes that such activities for prospects available in the Beaufort Sea OCS Planning Area would require, at the minimum, air dispersion modeling of NO_x emissions. Air dispersion modeling for an Arctic project is estimated to impose costs ranging from $200,000 to $250,000 for each proposed EP and DPP.

This estimate covers the initial and the follow-up rounds of air dispersion modeling for non-exempt NO_x emissions. This is a requirement under the baseline, thus BOEM is not assigning Arctic modeling costs to this proposed rulemaking.

Alaska Arctic Baseline Conclusion

BOEM does not expect Chukchi OCS projects to exceed the emissions exemption thresholds or to require air dispersion modeling or BACT emission controls under the baseline or proposed rule. BOEM expects Beaufort OCS projects under both the baseline and proposed rule to exceed the emissions exemption thresholds and require modeling, but not BACT. This is due to closer proximity to the seaward boundary for prospective Beaufort exploratory and development projects.

REGULATORY ALTERNATIVES

In accordance with OMB Circular A-4 guidelines for preparing economic analyses, BOEM analyzed options differing in their stringency from the proposed rule. These options reflect the major compliance cost categories for the proposed rulemaking.

Promulgating the Air Quality Regulations Now

The proposed rule is the promulgation of air quality regulatory changes now for GOMR (west of 87 degrees and 30 minutes longitude) and Arctic OCS. The section titled NEED FOR FEDERAL REGULATORY ACTION summarizes the primary regulatory changes in this proposed rule. The preamble of the proposed rule provides a more detailed discussion.

The bureau is updating the regulations to reflect BOEM responsibilities to regulate air emissions from BOEM-authorized activities off Alaska's North Slope, bring other references up to date with current practice, and improve the clarity of the regulation. The proposed updates, which require operators to submit additional air quality or modeling information to BOEM, are necessary for the bureau to evaluate the proposed action and to monitor the resulting OCS activity. These additional information requirements are necessary under and consistent with BOEM's statutory duty to protect the air quality of coastal states.

Regulatory Alternatives Analyzed

BOEM considered several regulatory alternatives for this rulemaking and is seeking public comments on many other regulatory alternatives or options in the preamble of the proposed rule. The alternatives considered in this RIA include:

1. Base Case. Taking no regulatory action and continuing to rely on existing air quality regulations and waiting until the Regional Exemption Studies are complete.
2. Tightening monitoring or recordkeeping provisions for approved plans (i.e., require all facilities to monitor their actual emissions or some key subset, such as facilities with

emissions above a certain amount or non-exempt facilities that were not required to model their emissions (more stringent alternative).

3. Requiring all plans to reduce emissions below the modeled SILs instead of the proposed action that requires a cumulative analysis compared with AAI when the SIL is exceeded for attainment areas (more stringent alternative).
4. Keeping the compliance measurement point at the shoreline instead of evaluating impacts at the state seaward boundary and continuing existing baseline practices regarding measurement periods and attribution of emissions (less stringent alternative).
5. Continuing the current policy of only requiring plan revisions when there are changes, rather than requiring resubmission each 10 years (less stringent alternative).
6. Regulating and evaluating emissions only from facilities. Attributed emissions from MSC or other sources would not be considered during BOEM's evaluation of the plan (less stringent alternative).

The regulatory alternatives analyzed here are intended to inform the public and industry on the range of costs and benefits that might be expected for alternative regulatory proposals. BOEM seeks cost and benefit information on other monitoring or emission reduction regulatory options that will economically reduce emissions and assure the air quality of states. The regulatory impact analysis of alternatives is summarized in the following sections.

Wait until the BOEM Regional Exemption Studies are Complete

BOEM is in the process of conducting new scientific studies to re-evaluate the exemption levels and exemption formulas. The studies will evaluate the current exemption threshold equations and examine whether recent advances in the field of air dispersion modeling, along with the availability of comprehensive meteorological datasets, can improve the exemption threshold analysis. To take "no regulatory action" would mean that the revisions to 30 CFR Part 550 (subparts A, B, C & J) would not be incorporated into BOEM's regulations and the intended benefits would not be realized. Waiting to publish these regulatory changes until 2018 or 2019, when both the Alaska and GOM exemption threshold studies are completed, would make it more difficult to ensure that BOEM meets its statutory duties. The amendments are necessary to ensure BOEM establishes up-to-date requirements and air quality standards are consistent with those identified by USEPA under the CAA, preparation of projected emissions, air dispersion and photochemical modeling, and control of emission sources. In addition, the purpose of the amendments is to ensure the consistent, efficient, and informed management of the OCSLA provision to ensure air emissions from BOEM-authorized activities on the OCS do not result in material impacts to state air pollution by the GOMR and Alaska OCS oil and gas operations.

The NAAQS are updated on an ongoing basis and it is BOEM's mandate to comply with the NAAQS. It is BOEM's current practice to update the SILs and AAIs and add the additional air pollutants for which standards have been established by the USEPA even without changes in BOEM's regulations. The compliance costs would likely increase even under the "no regulatory action" given the regulatory requirement to apply BACT for SIL exceedance in the current rule.

Allowable air emissions without regulatory action may be greater than the expected allowable emissions under the proposed action. This is primarily because the proposed regulatory changes clarify the treatment of attributed emissions. The proposed regulatory changes account for surface mobile sources, require consolidation of plans in certain situations, and evaluate the exemption threshold on a rolling 12-month schedule rather than only a calendar year. These changes are expected to increase the amount of attributed emissions for certain projects. The proposed changes would result in additional air emissions information being provided and likely increase in the number of plans containing ERMs. Operational controls, BACT or emission credits may be required as a direct result of the regulatory changes proposed in this rulemaking.

Regardless of whether the current regulatory action occurs now or is postponed, once these studies have been completed, BOEM anticipates that it will update the exemption threshold (currently at § 550.303(c) and § 550.303(d) in the proposed regulations).

Tightening Monitoring Provisions for Approved Plans

The USEPA requires monitoring of actual emissions on the primary emissions sources for an approved project. BOEM is only proposing to monitor *actual* emissions for select sources and circumstances as described in § 550.311. These sources are expected to be engines or equipment that are neither certified by the USEPA for domestic use or are not MARPOL-compliant. Monitoring actual emissions may be required when a plan is subject to post combustion BACT or offsets, or BOEM determines a facility may be causing or contributing to an exceedance of the NAAQS in any state. NAAQS exceedance is not assumed under the proposed rule 10-year operational scenario and no compliance costs are estimated for these provisions. Compliance costs are expected for the monitoring of actual emissions for non-certified engines. For all other emissions sources, recordkeeping and reporting of fuel consumption and activity will be required by fuel and activity logs in § 550.312.

The regulatory option analyzed here is the monitoring of actual emissions for any plan that (1) is not exempt, or (2) utilizes any ERMs including those proposed by the operator, operational controls required by BOEM or BACT. Operators under this alternative would be required to monitor actual emissions from enough of the plan emission sources to ensure that the actual emissions associated with facilities and MSCs under the approved plan are consistent with the projected emission limits approved for the plan.

NOx is the pollutant most likely to be in exceedance of the emissions thresholds or standards and the trigger pollutant that would require the monitoring of actual emissions. Therefore, NOx emissions would drive the number of large engines requiring emissions monitoring equipment. As Table 19 shows, the top four categories include almost all the NOx emissions.

Table 19 summarizes the GOADS 2011 NOx emissions estimates for oil and gas operations in the GOM and BOEM's assumptions on the percent of large engines in each category that will likely require a PEMs monitoring system under this regulatory alternative.

Table 19. GOM 2011 NOx Emissions

Derived from Table 7-5. Annual NO_x emission estimates for all sources (GOADS 2011)

OCS Oil and Gas Equipment/Source Category	2011 NOx Emissions (tpy)	Percent	Notes (percent = %engines in category)	Pop. Main Engines	Pop. Auxiliary Engines	Number of Max PEMs Engines
Support Vessels (682 vessels)	175,558	51.8%	Assume 75% Main Engines by yr 6	1497	694	1,123
Drilling Rigs	69,135	20.4%	Assume all Jackup & Semi main engines monitored; 90% drillship main engines by yr 5.	340	1,160	316
Natural Gas Engines	44,863	13.2%	Assume 40% by year 10.	1584		634
Natural Gas & Dual-fuel Turbines	27,264	8.0%	Assume 60% by year 10.	381		229
Pipelaying Operations	9,480	2.8%	Covered in Suppt Vessels.	N/A		N/A
Diesel Engines	8,927	2.6%	Assume 10% Large Engines by yr 10, no monitoring for <600hp.	275 (large >600hp)	1978 (small <600hp)	28
Drilling Equipment	1,493	0.4%				0
Boilers/heaters/burners	1,156	0.3%				0
Support Helicopters	753	0.2%				0
Combustion Flares	425	0.1%				0
Total Emissions (tpy)[a]	**339,054**	**100.0%**		**4,077**	**3,832**	**2,328**

[a] Totals may not sum due to rounding; Non-OCS source categories removed from table 7.5.

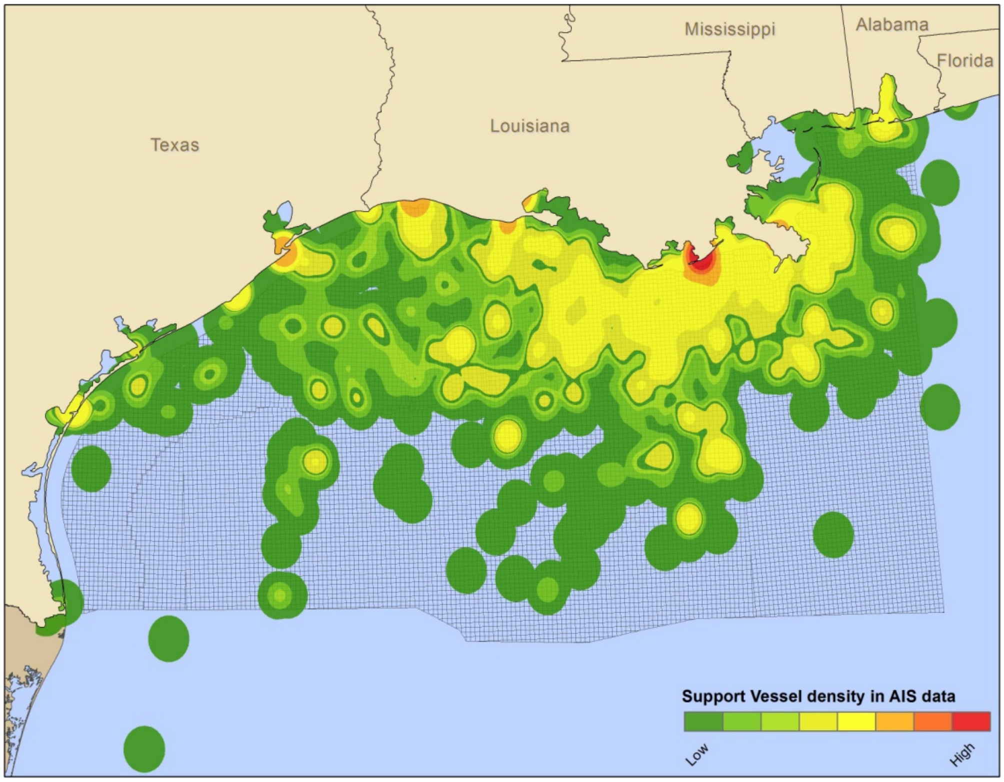
Support Vessels

The following sections provide additional information regarding BOEM's estimate for the number of large engines that would be required to monitor *actual* emissions under this regulatory alternative.

Figure 8 displays the support vessel density and corresponding emissions during calendar year 2011 from the BOEM GOADS inventory.[18] Readily apparent are the hotspots around the Gulf coast ports. The primary port for vessels supporting OCS operations is Port Fourchon in Lafourche Parish, Louisiana. The current air quality value in Lafourche parish is 71.00 ppb based on 2011-2013 USEPA data.

[18] BOEM OCS Study 2014-666: http://www.data.boem.gov/PI/PDFImages/ESPIS/5/5440.pdf

Figure 8. Gulf of Mexico OSV Concentration (2011)



Based on the 2011 GOADs inventory, there are about 682 vessels supporting OCS operations. These support vessels (including pipe laying operations) are estimated to contribute almost 55 percent of the NOx emissions from OCS operations. If all plans not exempt or employing ERMs are required to monitor enough of the plan's actual emissions to assure compliance, BOEM estimates that most OSVs would require a PEMs type monitoring system. Based on BOEM's best estimate of the volume of emissions, number and size of vessel engines -- a total of 75 percent of the vessel main engines, or 495 out of the 682 GOM vessels, would need a PEMS.[19] Only the support vessel main engines are expected to require PEMs and the monitoring of actual emissions.

This analysis does not assume that PEMs monitoring of actual emissions will be required on auxiliary engines. Support vessel auxiliary engines are not expected to contribute material emissions to plan totals. BOEM estimates that under this scenario the early years will require many PEMs units to be installed. In the later years, there will be fewer deployed until a total of 1,123 PEMs units are estimated to be required on support vessels.

Table 20 below summarizes the assumptions used for PEMs monitoring.

[19] Because some vessels have more than 2 main engines, the number of vessels is slightly less than 75%.

Table 20. OSV PEMs Estimate

	Count	Percent PEMs	Count PEMS
GOM Vessels (2011)	682	N/A*	495
Support Vessel Main Engines (est.)	1497	75%	1,123
Support Vessel Auxiliary Engines (est.)	694	0%	0
*The number percentage of vessels with PEMs is less than the percentage of engines since the larger work boats have more than 2 main engines.			

MODUs

Under this regulatory alternative BOEM assumes that operators would most likely require MODUs operating on the OCS to install PEMs as part of the lease operating agreement. BOEM assumes that PEMs would only be required on the main engines and not on auxiliary engines. For this analysis BOEM assumes on average 8 PEMs engines on a drillship, 6 PEMs engines on a semisubmersible and 4 PEMs engines on a jackup rig (Table 21).

Consistent with other analysis in this RIA, BOEM assumes a long-term count of 10 jackups, 10 semisubmersibles and 30 drillships operating on the OCS.

Table 21. Estimate of PEMs Units on MODU Main Engines

	Count	**Main Engines**	**% w/ PEMs**	**PEMs Engine Units**
Jackups	10	4	100%	40
Semisubmersibles	10	6	100%	60
Drillships	30	8	90%	216
			Total:	**316**

Platform Engines

Consistent with the assumptions in Table 21, under this regulatory alternative the number of PEMs units expected to be installed on platform engines is shown in Table 22 below.

Table 22 Platform Engine PMEs Units

Engine	**2011 Platform Engines (GOM)**	**Percent PEMS**	**Est. PEMs Engine Units**
Diesel - Lg	275	10%	28
Diesel - Small	1,978	0%	0

NG Eng	1,584	40%	634
NG Turbine	381	60%	229
Grand Total	**4,218**		**890**

PEMs Monitoring Summary

Table 23 summarizes the number of engines that could require PEMs monitoring under the regulatory alternative in which BOEM requires monitoring of actual emissions for the largest sources of non-exempt plans or plans utilizing ERMs.

Table 23. Estimated Number of Engines Requiring PEMS under Regulatory Alternative

Engine Type	Count
Support Vessel Engines	1,123
MODU Main Engines	316
Large Platform Engines	891
Grand Total:	2,330

PEMS Operating Cost Summary

Monitoring of actual emissions requires a CEMs or PEMs type system for each of the sources (engines or turbines) with emissions. A PEMs system's installation cost on a vessel or MODU engine can range from \$100,000 to \$156,250. The annual operational cost is estimated to be about \$3,750. This operating cost estimate could increase following the first few years of operations as repairs and calibration become more frequent. The 10-year amortized annual cost for these figures is \$19,200 to \$26,000 per engine. BOEM welcomes any additional information on the expected operating costs for PEMs on OCS vessels or platforms.

If BOEM required the monitoring of actual pollutant emissions for plans that are not exempt or utilize any ERMs, the compliance costs would be substantial. The requirement to monitor actual emissions would be determined by the plan's cumulative emissions, but the number of sources or engines covered in a plan drives the monitoring cost. The number of "monitored" engines each year under this alternative is expected to increase as plans are submitted or resubmitted to BOEM and then approved. Some of those plans will decay, but others exceeding the exemption threshold or employing ERMs would be added each year.

The number of covered engines under this scenario in the first year is estimated to be 494, climbing to 2,328 in the tenth year. The compliance cost estimates for monitoring *actual* emissions on GOM plan sources utilizing PEMs ranges from \$9.5 million (\$19,200 annual cost/engine) to \$12.8 million (\$26,000 annual cost/engine) in the first year. By the tenth year, the annual cost escalates to a range between \$46.6 million and \$63.1 million. Discounted at 3% the 10-year cost would be \$393.3 million (\$26,000 annual cost/engine).

Benefit of Increased Monitoring of Actual Emissions

Because BOEM typically analyzes "worst-case" emissions, it is unlikely the cumulative emissions for a plan would be found to exceed a threshold through the monitoring of actual emissions. Based on historical BSEE compliance data for mitigated plans reporting fuel and activity information, there are occasional individual sources within a plan that may exceed. BOEM believes the existing monitoring provisions under § 550.312, which require retention of fuel and activity logs and reporting to BOEM/BSEE, would provide adequate monitoring and compliance information for most plan situations.

BOEM does not expect that emissions would be reduced by any material amount through monitoring of actual emissions (with PEMs) versus estimating plan emissions with emissions factors and fuel/activity information provided under § 550.312. The emissions factors used by BSEE to estimate monthly emissions will be the same factors approved by BOEM during the plan approval process. BOEM believes source emission factors combined with monthly fuel consumption and activity data provide reasonably accurate estimates of actual emissions for compliance purposes.

BOEM Would Only Approve Plans with Modeled Emissions below the SILs

This stricter regulatory alternative would require all plans with modeled emissions above SILs to utilize operational controls, BACT or offsets sufficient to reduce the modeled emissions below a level that would cause an exceedance in the SIL, regardless if the state measurement point is in an attainment or nonattainment area. The proposed rule only requires emissions below a level that would cause an exceedance in the SILs for non-attainment areas. This regulatory alternative is generally consistent with BOEM current practice.

The proposed regulatory provisions at 30 CFR § 550.305 to § 550.309 provide the conditions under which ERMs are required. If the estimated emissions do not exceed the exemption threshold, no modeling or ERMs are required. If a plan's emissions are above the exemption threshold and combined photochemical modeling and air dispersion modeling indicate there is a potential impact to States though exceedance of the SIL for a criteria pollutant (NOx assumed) or NAAQS, ERMs are necessary. The required type, nature and duration of ERMs depend on the pollutant, whether the facility is a short-term or long-term facility *and* whether the state area impacted is attainment or nonattainment.

Short-Term Facilities

Where modeling indicates exceedance of a criteria pollutant's SIL or NAAQS, the use of ERMs is dependent upon whether the plan is for a short-term or long-term facility. For a short-term facility the operator must:

> *Select reasonable operational controls or replacement(s) of equipment that are technically and economically feasible and that are designed to limit your facility's projected emissions to the greatest practicable extent, taking into consideration the effectiveness and the cost of implementation, for each option considered* (§ § 550.306(a)(5)).

A short-term facility is typically a MODU conducting exploratory drilling. Most EPs are under the exemption threshold and don't require modeling. For those EPs where modeling is required, BOEM believes in most cases operational controls including the use of Tier-2 engines will be sufficient to keep plan emissions below the SILs. Following the completion of the regional exemption studies, BOEM will have better information to assess the likelihood of SIL exceedance for short-term facilities.

Long-Term Facilities

The impact of this alternative is most likely to adversely impact DOCD or DPPs for long-term facilities. A development plan is more likely to exceed the SIL since there are additional operations contributing to emissions. These additional operations include construction, drilling with one or more MODUs, and production.

If emissions from a long-term facility are estimated to generate concentrations of air pollutants onshore in excess of the SILs, the operator must then determine whether the resulting emissions will impact attainment or nonattainment areas. The operator must analyze ERM options and proposed emission reductions sufficient to ensure the NAAQS is not exceeded. In an attainment area where the AAIs are not exceeded, the proposed rule requires BOEM to impose cost effective [operational] controls. If the AAI is exceeded, sufficient ERMs (i.e., BACT, operational controls or offsets) would be required to reduce concentrations of air pollutants at the compliance boundary or onshore.

Benefit of Requiring ERM for all SIL Exceedances

This regulatory alternative is consistent with the existing BOEM air quality regulations which requires BACT if the SILs are exceeded. However, OCSLA only requires DOI to protect the NAAQS. While emissions controls for SIL exceedance certainly protect the NAAQS, BOEM believes the use of the AAI and cumulative analysis of plan emissions also protects the NAAQS and is more consistent with the provisions of the OCSLA for attainment areas.

Since there are emissions reductions under this alternative, there would be quantifiable benefits. The net benefits may depend on the cost of emissions credits (estimated at $3,000/tpy) and the estimated benefit (estimated at $5,000/tpy) for reducing ton on NOx. However, the compliance cost for actual OCS emissions reductions necessary (most likely SCR BACT) to bring long-term facilities impacting attainment areas below the SIL are unlikely to yield net benefits at a benefit of $5,000/ton of NOx.

Continue Current Emissions Measurement Practices

This regulatory alterative would retain the current regulations and continue current practice where measurement points, measurement periods and attribution of GOM emissions would remain unchanged (less stringent alternative). This regulatory option would:[20]

- Continue to measure impacts to a state's air quality at the closest shoreline point to the facility rather than the state/federal submerged lands boundary.
- Allow for calendar year rather than 12-month rolling average measurement of air emissions for the threshold analysis.
- Allow the submission of different DOCDs or DPPs for projects on separate fields even if tying back to the same complex.
- Retain the 25-mile radius limit for MSC emissions rather than including all MSC emissions.
- Eliminate re-modeling for those plans that are at 95% the SIL or apply ERM.

This regulatory alternative would significantly reduce air dispersion and photochemical modeling costs. It may also permit some plans that would be required to employ ERM under the proposed rule to no longer utilize emission reduction measures.

Most of the assumptions for these regulatory alternatives are found in the *Modeling Compliance Costs* section. This regulatory alternative retains the regulatory baseline for the five bulleted items. If BOEM does not adopt the proposed rule provisions, the compliance costs would not be incurred. Table 24 below provides the estimated cost and benefit changes if the baseline provisions are retained. Costs would be reduced by $33 million and benefits reduced by $43 million in the peak year 2020.

Keep the Point of Impact Measurement at the Shoreline

Instead of evaluating impacts at the state seaward boundary beginning in 2020, BOEM would continue to measure impacts to a state's air quality at the closest shoreline point to the facility. This alternative is consistent with DOI's longstanding practice and BOEM's current regulations.

Movement of the compliance measurement point 3.4 or 10.3 statute miles (3 or 9 nautical miles) seaward increases the number of plans required to conduct air dispersion and photochemical modeling. The plans closest to the compliance measurement boundary receive the 100 tons per year exemption. There are very few plans with estimated emission below 100 tons per year of NOx; some of the plans closest to shore may require ERM after modeling state air quality impacts. All of the plans submitted during 2014 that would benefit from this alternative are in the Central Planning Area. Louisiana is the closest state to most facilities.

[20] Separating out the individual effects of any single one of these policies is problematic because of the interdependence of policies on the extent of aggregate modeling and resulting emission reductions that will be required. In particular, each individual policy could potentially allow a project with certain characteristics to remain under the exemption threshold and thereby avoid modeling. Accordingly, the true incremental cost of any one policy is dependent on the set of remaining policies selected. As such, the aggregate compliance cost of these proposed changes are best estimated cumulatively. However, for this regulatory alternative analysis we are prorating the modeling and ERM costs across the policy options by the number of plans in Table 23 to approximate the reduced regulatory compliance cost attributable to each policy if the regulatory baseline is retained.

The measurement point in the Western Planning Area (WPA) is 10.3 statute miles closer to the facility but only 5 percent of plans submitted in 2014 were in the WPA. None of the 2014 WPA submitted plans would have been pushed into modeling or ERM with the 10.3 statute mile point of measurement offshore Texas.

Movement of the compliance measurement point is also expected to contribute to a greater number of plans utilizing ERMs because of the closer measurement point for modeling receptors. Under this alternative (and the current rule), plans are allowed to emit 113 (LA, MS, AL) or 343 (TX) more tons per year of criteria pollutants during any 12-month period before modeling and subsequent analysis is required. This assumes BOEM continues utilizing the current exemption formula. BOEM estimates this regulatory alternative (compliance measurement point kept at the shoreline) could result in up to 30 fewer plans per year required to perform air dispersion or photochemical grid modeling than if the proposed rule's provision to more the compliance measurement point to the submerged lands boundary is adopted.

Retain Calendar Year Measurement

Instead of evaluating emissions on a rolling 12-month average, BOEM would continue to evaluate project emissions on a calendar year basis. This alternative is consistent with BOEM's current practice and interpretation of current regulations.

This alternative would mostly benefit submitters of exploration plans since development drilling and operations traditionally extend over many years. BOEM estimates that about 10 additional plans may be pushed above the emission threshold and require modeling due to measurement of emissions on a 12-month rolling average rather than calendar year basis. If BOEM does not adopt this provision, the compliance costs would not be incurred.

Allow Plans' Air Quality Analysis for Separate Fields Even if Tying Back to a Single Complex

Instead of requiring consolidation of all proximate satellite project emissions for an air quality analysis of complex total emissions, this alternative would permit separate DOCDs or DPPs and corresponding air quality analysis under certain conditions. BOEM estimates that about 15 additional plans per year may require modeling when all required proximate or project emissions are analyzed together. This alternative is consistent with BOEM's current practice in the GOM. If this provision is not adopted, the compliance costs would not be incurred.

Retain 25-mile Limit for Attributed Emissions

Instead of including all mobile emissions in a plan's air quality analysis, BOEM would continue to only require a plan's air quality analysis include support vessel emissions within 25 miles of the point source. Under the proposed rule support vessel emissions would be included whenever a vessel is operating in support of a regulated facility, regardless of distance. This alternative is consistent with BOEM's current practice, the USEPA's current regulations.

This alternative would benefit plans submitted for projects greater than 25 miles from the state/federal measurement point. BOEM estimates that about 5 additional plans may be pushed above the exemption threshold and require modeling when all support emissions are included. If this provision is not adopted, the compliance costs would not be incurred.

Remove the 95% Threshold for Remodeling

Under the proposed rule if emissions are modeled at 95 percent of the SIL, operators must remodel following any emission reduction measures or addition of aircraft emissions and applicable emissions from onshore support facilities (§ 550.205(m)). BOEM assumes NO_x would be the exceeding pollutant and estimates that up to 20 plans per year would require remodeling under this proposed provision (Table 3, Table 4 and Table 24). If this provision is not adopted, the compliance costs would not be incurred.

Modeling Cost Savings

The assumptions for the estimated modeling cost savings for retaining the baseline regulations are found in the *Air Dispersion Modeling Compliance Costs* section. These estimates assume no changes in the exemption formula. These estimates also assume that consistent with the baseline and recent BOEM GOM experience, air dispersion modeling does not show an impact to state air quality or the need for emission reduction measures.

The estimated modeling cost for each plan beginning in 2020 is $120,000. This $120,000 cost includes $20,000 for air dispersion modeling, $50,000 for $PM_{2.5}$ photochemical grid modeling and $50,000 for ozone photochemical grid modeling. A cost savings of $120,000 for each plan is assumed if one of the regulatory alternatives are adopted and modeling is no longer required because the plan's emissions do not exceed the exemption level.

ERM Cost Savings

ERM NO_x credits are estimated to cost $3,000 per ton of NO_x reduced. The foregone purchased credits are assumed to be a cost savings in this regulatory alternative analysis. The use and assumptions regarding ERM credits is found in the *Emissions Reduction Credits* section. The ERM compliance cost savings from adopting this alternative are uncertain, but consistent with the current baseline, BOEM estimates that absent these new regulatory requirements ERM or BACT is unlikely to be required under current BOEM regulations and USEPA air quality standards. Consistent with the modeling costs ERM credits are prorated across the different regulatory alternatives in the same proportion as plans.

The cumulative result of the proposed rule's plan consolidation, attributed emissions, movement to a 12-month rolling average along with the movement of the compliance measurement point all contribute to additional plans requiring modeling and ERMs. Under this alternative fewer plans would be required to model and the magnitude of ERM savings is expected to be positive, but quantification is uncertain. Modeling results and the attainment status of the impacted area are all key components to estimate the compliance saving from this alternative.

Table 24 is a first-order estimate of the costs for each proposed regulatory change. ERM costs are prorated by number of plans across the alternatives absent specific project information. Table 24 presents the estimated 1st year, Peak year and 10th year cost savings if BOEM retains the existing [baseline] regulatory provisions and practices. If this regulatory alternative was adopted (no measurement regulatory changes) the rule's estimated compliance costs would be reduced by the cost figures in Table 24.

Lost Benefits for Regulatory Alternative(s)

If modeling indicates that NOx emissions would cause an exceedance of the SILs, emission reduction measures will be necessary. It is difficult to estimate exactly how many fewer plans may be required to propose ERMs if any single one of the baseline process/regulatory provisions identified in this section is retained. Some of the proposed regulatory provisions (*calendar year measurement*, *plan consolidation*, *25-mile MSC emissions*) could increase the emissions attributed to a plan, while another (*movement of state/federal measurement point*) could decrease the emissions allowed before modeling is required.

If the proposed regulatory changes are not made and the baseline continues, there could be fewer emission reduction measures applied and thus reduced air quality benefits. This may especially be the case in the 2017-2024 timeframe when several Louisiana parishes are expected to be nonattainment areas and some plans would most likely be required to significantly reduce emissions so that a plan's impact on a state's air quality is below the SILs. Based on the estimate of emissions credits purchased, the forgone benefits associated with this regulatory alternative could be up to $26.5 million of NOx reductions in 2017, $43.1 million in 2020 and $0.0 in 2026. These figures are also shown in Table 24.

Table 24 Proportioned Costs/Benefits of Regulatory Alternative(s)

MM$	Additional No. Plans (2017)	Est. Modeling Cost (2017) [no photochemical]	Est. ERM Cost (2017)	Additional No. Plans (2020-2026)	Est. Modeling Cost (2020-2026)	Est. ERM Cost Peak Yr (2020)	Est. ERM Cost 10th Yr (2026)
Estimated Reduced Compliance Costs							
Shoreline State/Federal Measurement Pt.	N/A	N/A	N/A	30	$3.6	$12.9	$0.0
Retain Calendar Yr Measurement	9	$0.2	$5.3	10	$1.2	$4.3	$0.0
Forgo Plan Consolidation	12	$0.2	$7.9	15	$1.8	$6.5	$0.0
25-mile radius for MSC emissions	4	$0.1	$2.6	5	$0.6	$2.2	$0.0

Eliminate re-modeling (95% SIL)	15	$0.0	N/A	20	$0.0	N/A	N/A
TOTAL:		**$0.5**	**$15.9**		**$7.2**	**$25.9**	**$0.0**
Estimated Reduced Air Quality Benefits							
NOx Reduction Benefits (credits):			**$26.5**			**$43.1**	**$0.0**
Cumulative Net Benefit Change for Regulatory Alternatives:							
		$10.1			**$10.0**		**-$7.2**[21]

Net Benefits from Regulatory Alternative

Whether the net benefits from this regulatory alternative are positive or negative is difficult to determine with certainty. The ERM credit costs could be significantly higher and possibly outweigh the benefit of emission reductions. On the other hand if there were economical reductions through credit purchases occasioned by the measurement point change or manner in which emissions are attributed to a plan or analyzed, the net benefits could be positive. Table 24 provides BOEM's best estimate of the potential forgone net benefits under this regulatory alternative(s).

Only Require Plan Revisions when there are Changes to the Plan

The proposed rule in § 550.310 requires that plans be resubmitted each 10 years beginning in 2020 even if there are no material changes to the plan. This regulatory alterative would continue the current practice where plans are only resubmitted if there are material changes (less stringent alternative).

The intent of the proposed rule's plan resubmission provision is consistent with the objective of OCSLA section 5(a)(8), which requires BOEM to ensure compliance with the NAAQS. The public benefit is that all plans will periodically be reevaluated and all of the applicable requirements of regulations in effect on the date of resubmission would apply. This regulatory alternative is only expected to impact DOCDs and DPPs. Exploration plans usually only active for a couple years and are seldom active more than three years without revisions which require a new air quality analysis.

The most common reasons DOCDs are revised and receive new air quality analysis are changes to drilling operations, equipment or vessel changes, construction, cleaning the wellbore with chemicals, provide more time for drilling or decommissioning. Changes to drilling operations could involve sidetracks, new wells, water injection wells or workovers. In practice companies often resubmit DOCDs in advance of selling leases to another operator so the new operator can be assured the plan is in compliance.

[21] The year 2026 includes the modeling cost estimates that are flat lined from 2020-2026.

The typical life of DOCDs varies significantly. While each plan and project is different, the typical life of a DOCD depends whether the facility is on the shelf or in deep water and whether production is primarily oil or gas. Most drilling in the GOM is targeting oil; natural gas projects are becoming less frequent.

- The shortest production periods and life of a DOCD is for **shelf gas**. Most shelf natural gas wells do not produce much longer than 5 years before the well is plugged and abandoned, is worked-over or a sidetrack drilled. These operations require a revised plan.
- The production period for **shelf oil** wells usually lasts about 8-10 years and longer with secondary recovery, workovers or sidetracks. Most shelf-oil projects will submit a revised DOCD around the 8-10 year mark if not earlier.
- While the production life of **deepwater gas** wells can last longer than shelf gas, the economics and methane hydrate challenges results in most deepwater gas wells with production lives of around 5-7 years and sometimes less.
- Deepwater oil wells typically have the longest production lives and are expected to produce for more than 10 years. However DOCDs almost always have some change during the first ten years of deepwater operations where a revised DOCD is submitted.

While there is no hard and fast rule for any specific OCS project, most DOCD plans will be revised before reaching the 10-year mark. In 2014 only 30 new DOCDs were submitted to BOEM, the remaining approximately125 plans were supplemental or revised DOCDs. BOEM conservatively estimates that this provision could require up to 15 DOCDs/DPPs per year to be resubmitted before operators would typically submit a revised a plan, although the actual number is likely to be much less.

Estimated Cost Savings from Continuing Current Practice

The cost savings for this regulatory alternative assumes:

(1) 15 DOCDs/DPPs are resubmitted each year due to the proposed resubmissions provisions of § 550.310
(2) A 400 hour burden for resubmission. This includes up to 200 hours for the air quality analysis and 200 hours for other components of the plan.
(3) No modeling or other cumulative analysis is required

BOEM estimates cost savings of up to $14,800 per plan or $222,000 per year for this provision. Please see § 550.310(c) in Table 15.

Regulate and Evaluate Emissions from Facilities Only (exclude attributed emissions)

This regulatory alternative would remove MSCs or other sources of attributed emissions from being considered during BOEM's plan evaluation (less stringent alternative). Consistent with the assumption used elsewhere in this RIA, NOx is the criteria pollutant that is most likely to cause exceedance.

The most recent Gulf-wide air emission inventory was conducted in 2011. Drilling activity and potentially OSV activity has increased since 2011 but BOEM believes this inventory is representative of impact if attributed emissions were excluded from plan air quality analysis. Table 25 shows the estimated 2011 NOx emission for the Gulf of Mexico.

Table 25. Gulf of Mexico NOx Emissions (GOADS 2011)

OCS Oil and Gas Equipment/Source Category	2011 NOx Emissions (tpy)	Percent
Support Vessels (682 vessels)	175,558	51.8%
Drilling Rigs	69,135	20.4%
Natural Gas Engines	44,863	13.2%
Natural Gas & Dual-fuel Turbines	27,264	8.0%
Pipelaying Operations	9,480	2.8%
Diesel Engines	8,927	2.6%
Drilling Equipment	1,493	0.4%
Boilers/heaters/burners	1,156	0.3%
Support Helicopters	753	0.2%
Combustion Flares	425	0.1%
Total Emissions (tpy)[a]	**339,054**	**100.0%**

Derived from Table 7-5. Annual NOx emission estimates for all sources (GOADS 2011)
Totals may not sum due to rounding; Non-OCS source categories removed from table 7.5.

As seen in the largest emission category (Support Vessels), more than half of the GOM OCS oil and gas operations NOx emissions originate from OSVs. These attributed emissions would not be included or considered in plans if BOEM adopted this regulatory alternative. It is BOEM's current practice to consider all attributed emissions within 25 miles of the facility which includes a majority of attributed emissions.

Under this alternative fewer plans would be required to model air emissions or employ emissions reduction measures. The cost savings to industry would be substantial since very few plans would require modeling or ERMs. BOEM estimates that less than 15 plans would exceed the emissions threshold and be required to model under this alternative. It is doubtful those plans would be required to employ ERMs. While the industry compliance costs would decline, BOEM does not believe that alternative is consistent with the objective of OCSLA section 5(a)(8) which requires BOEM to ensure compliance with the NAAQS.

PROPOSED RULE BENEFITS

Quantitative Benefits

The proposed changes could provide *quantitative benefits* and require some exploration or development projects to use operational controls or employ other ERMS. If this were to occur, the on-shore air quality would be improved over the existing baseline.

When fuel is combusted, some nitrogen (N2) and oxygen (O2) combine and form compounds like nitrogen dioxide (NO2) and nitric oxide (NO). Once released into the atmosphere, NO_x contributes to the creation of particulate matter, ground-level ozone (smog) and acid rain. A reduction in OCS air pollutants including NO_x reduces the risk of premature mortality in the U.S. population. However, it is very difficult to estimate benefits for NOx reductions offshore because of the long distance between OCS operations and onshore population centers.

The operational controls most likely to be required by BOEM for SIL exceedance are the use of "Good Combustion Practices" as outlined by the engine manufacturer combined with the use of an engine performance management system or similar system to minimize thermal NO_x formation. An engine performance management system (EPMS) is designed to optimize MODU engine loads for the anticipated demand and triggers an alarm if the NO_x concentration reaches a specified threshold, at which time the operator will investigate the cause of the emissions increase and quickly correct the underlying problem.

The EPMS system is new and will be tested on several 6th generation drillships due to enter the GOM drilling fleet in 2016. At this time, the EPMS offers great promise for better managing engine loads to both reduce fuel consumption and the corresponding NOx emissions. The NOx reductions possible with an EPMS type system depend heavily on the vintage of the engine and must also consider synergistic interactions with other engine technologies. According to industry sources, the optimization of EPMS could take about three years of testing and refinement beginning in 2016. BOEM expects that industry's incentives to economize fuel usage and optimize engine loads, combined with the tighter emission limits in this proposed rule, will incentivize the development and optimization of EPMS or similar technology by 2020. The year 2020 is when BOEM expects to implement the new emissions threshold formula and move the compliance boundary to the state-federal submerged lands boundary.

A first order estimate of the NOx reductions possible for operational controls under the proposed rule is a 15 percent NOx reduction for about 11 MODUs per year beginning in 2020. BOEM estimates up to 11 MODUs could be part of projects where modeling shows the SIL is exceeded due to drilling in attainment areas. These projects are expected to be less than 100 miles from shore on the GOM shelf or in the Mississippi Canyon area. BOEM estimates that these projects will utilize 2 jackups, 2 semisubmersibles and 7 drillships. A 15 percent NOx reduction for these 11 drilling MODUs is estimated to eliminate about 3,600 tons per year of NOx. Based on those assumptions, a benefit of $5,000 per ton per year of NOx reduced, the monetized benefit of an improved air environment is *$18 million per year*. However, as discussed in the section titled "Operational Controls" an engine performance management system may ultimately be prohibited by a proposed Coast Guard Rule. Therefore, while we provide here in the text the estimated benefits from adopting this control measure, we have not included these estimated benefits in the proposed rule's net benefit calculation shown in Table 26.

NOx Reduction Benefit Values

The best available source of a benefit estimate for OCS NOx reductions is the BOEM Offshore Environmental Cost Model (OECM), primarily used to estimate the social and environmental costs for projected OCS exploration and development activity.[22] The OECM includes an air quality module that estimates the monetary value of the environmental damage caused by these air pollutants including NOx (estimated on a dollar-per-ton basis). The OECM dollar-per-ton values are derived from a modified version of the Air Pollution Emission Experiments and Policy (APEEP) analysis model. The OECM assumes sources closer to land cause greater damage per ton than sources farther from shore. Offshore sources located near large cities tend to cause greater damage than sources offshore from rural areas, and the importance of prevailing winds is clearly evident. The estimated GOM NOx damages on a $/ton basis are shown previously in the OECM Figure 7.

Based on recent historical trends, most of the project GOM exploration and development activity is expected to occur in the dark orange areas of Figure 7 associated with $/ton damages of $4,001 to $6,000. This area includes the Mississippi Canyon area and near shore areas where NOx emission reductions may be required by this proposed regulation. BOEM is using a benefit estimate of $5,000 per ton of NOx reduced which is the midpoint of the $4,001 to $6,000 range.

Pollutant Reduction Benefits (other than NO_x)

Reductions of any pollutant would cause an improvement in air quality and a reduction in adverse health and other effects. There could be co-benefits for pollutant reductions for other criteria pollutants than NO_x when operators use good combustion practices or tier-2 engines. BOEM is not estimating quantitative reductions for pollutants that are not required reductions. This analysis assumes that NO_x would be the only exceeding pollutant.

Good combustion practices economize fuel consumption and are already a standard practice for most operating companies. Similar to engine performance management systems, BOEM is not estimating co-benefits for other pollutant reductions other than NO_x due to the uncertain nature of these reductions and the uncertainty about when these reductions could be credited to the proposed rule.

Qualitative Benefits

[22] BOEM OCS Study 2012-025 Forecasting Environmental and Social Externalities Associated with OCS Oil and Gas Development: The Revised Offshore Environmental Cost Model http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Leasing/Five_Year_Program/2012-2017_Five_Year_Program/OECM.pdf

The qualitative benefits for the proposed regulatory changes include improved uniformity of regulations for all areas within DOI air quality jurisdiction. These changes link to EPA regulations and provide predictability and consistency for operators. Further, with the proposed changes to the regulations, BOEM will have one uniform set of requirements which will be more effective and increase lessee compliance.

The proposed regulatory changes will also provide BOEM and affected states improved information on the expected onshore air quality impacts of OCS exploration and development. This improved air emission information will ensure BOEM only approves plans that meet OCSLA requirements. Coastal states and other stakeholders can be more confident regarding the expected onshore air quality impacts from OCS exploration and development. The additional monitoring information submitted for mitigation plans will permit BSEE to better assess the air quality compliance for OCS operations. In particular, the requirement for projects exceeding the exemption threshold to provide actual emissions information via modeling will provide BOEM and BSEE more information to monitor the emissions from projects to ensure that they do not exceed exemption thresholds. Similarly, the required line dispersion modeling for mobile sources will provide a complete inventory and more accurate assessment of vessel emissions and their impact on coastal states.

The qualitative benefits are realized through consistency with EPA and state programs, as well as more efficient identification and mitigation of emissions. These benefits may include:

1. Consistency with the EPA's methodology, standards and analytic approach
    - Consistency with the EPA would ensure that the program adopted by BOEM is effective in accomplishing the mission it is charged to perform
    - Provide a compatible mechanism for regulating similar resources between two different federal agencies thereby minimizing confusion and simplifying compliance
    - By BOEM utilizing a similar approach to USEPA, companies can more readily obtain necessary resources to secure compliance, since the pool of knowledgeable contractors will be much greater and the requirements will be more easily understood
    - Companies will be able to more easily take advance of compliance mechanisms and technologies that they use in other contexts (emissions monitoring, controls, etc.)

2. Reduce costs to States
    - Given that the States are required to comply with EPA mandates, and that potential emissions of air pollutants from the OCS could affect onshore air quality, the effective management of OCS emissions would reduce the States' compliance costs
    - The more effectively BOEM manages the air quality on the OCS, the less the States would be required to monitor or evaluate the potential OCS impacts to their State Implementation Plans (SIPs)
    - If BOEM could effectively monitor ambient air quality over state submerged lands, this could facilitate States' cost-effective compliance with EPA air quality monitoring and tracking requirements
    - In the event of disputes over the source and extent of the impact of any OCS facility on a State, the review and appeals process would be streamlined compared to the current process

3. Increased development potential in the States
    - To the extent that OCS emissions do not impact the States (due to effective air quality management by BOEM), the States would have a greater ability to approve new or incremental oil and gas development over state submerged lands or onshore
    - If BOEM ensures that OCS emissions do not affect the attainment status of any onshore areas, additional onshore facilities could be approved and existing facilities maintained that might otherwise not be approved or required to apply potentially costly controls (or shut down entirely)
    - Air quality improvements could potentially benefit commercial and recreational fishing, marine mammals, migratory birds, marine habitats, etc.

4. Increase compliance through improved OCS emissions information and potential emissions reductions
    - More complete assessment of emissions through the use of "combined total emissions," and "attributed emissions" which allows BOEM to access all OCS emissions and require controls where needed
    - New air quality analysis for ROW and RUE applications, which will include pipeline construction emissions, and potential control for those emissions for the first time
    - Application of operational controls where needed
    - More effective application of emission reduction measures due to better guidelines
    - More rapid detection and prevention of excessive emissions through the use of ambient air monitoring, along with a better ability to identify the sources of contamination

5. Reductions in lessee/operator AQRP compliance costs
    - <u>If</u> satellite monitoring is realized, the use of OCS ambient air quality data would substantially decrease the actual emissions monitoring on facilities that would otherwise have been required to ensure ongoing compliance
    - The use of offsets and mitigation banks could significantly lower the cost of reducing emissions, as compared to SCR BACT
    - BACT would be required only in situations where there is no other more cost-effective or feasible alternative necessary to prevent a violation (i.e., BACT is averted when SILs are exceeded but where AAIs are not exceeded)
    - Emissions limits could be relaxed in those situations where further reductions in the emissions of ozone precursors would be ineffective (i.e., NO_x or VOC-saturated areas)

6. Judicious application of controls, when required
    - Increased likelihood that emissions controls are implemented when necessary to prevent a violation in the NAAQS (i.e., when previously grandfathered facilities are now required to implement reductions that they would not have been required to do)
    - A provision where the Regional Supervisor can temporarily order the suspension of equipment that emits air pollutants when an adjacent state or locality declares an air quality episode or emergency.
    - Improved likelihood that lessees will replace antiquated equipment with newer or less polluting equipment (particularly swapping engines from diesel to natural gas

- Better detection of likely contributors to potential violations (i.e., use of more robust standards, such as 1-hour NO_x and multiple averaging times)
- Ability to incorporate ambient air quality monitoring technologies as they are developed and perfected

7. Enhanced protection of the air over state submerged lands:
   - Adverse changes in air quality detected more quickly and sources identified more accurately
   - NAAQS nonattainment is recognizable in smaller areas or regions than are currently classified by the EPA and in areas on the OCS, which is currently unclassified. This would improve air quality compliance with OCSLA.
   - The proposed rule would facilitate BOEM identifying and responding to causes of ozone and $PM_{2.5}$ formation that could not previously have been determined or evaluated

The proposed rule allows BOEM to further its mission of environmental protection and economic development through responsible, science-based management of offshore energy resources. There are numerous non-monetized, qualitative benefits attributable to the rule that would provide for more regulatory certainty and an overall cleaner air environment. Some of the benefits described above will take effect immediately with the implementation of the rule, while others will phase in over some time period as technological innovation occurs.

ESTIMATED RULEMAKING NET BENEFITS

Based on a consideration of the qualitative as well as quantitative factors related to the rulemaking proposal, BOEM's assessment is that the proposed regulation is necessary to achieve compliance with the requirements of the OCSLA and that its adoption would provide a net benefit to the public. However, BOEM estimates the quantified net benefits for this proposed rule will be negative in each year after 2019. The estimated quantified benefits from emissions reductions measures are exceeded by the cost of the emissions reduction measures and the increased modeling and monitoring costs. Table 26 summarizes the annualized proposed rule's estimate of net benefits.

Table 26. Estimated Annualized Rulemaking Quantified Net Benefits

MM$ nominal Years -->	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Estimated Industry Compliance Costs	$22.9	$29.9	$35.9	$49.4	$45.1	$36.6	$31.5	$31.7	$27.7	$28.4
Estimated Benefit NOx Reductions	$26.5	$35.3	$43.1	$43.1	$34.3	$18.6	$8.8	$7.8	$0.0	$0.0
Estimated Net Benefit	$3.5	$5.4	$7.2	-$6.3	-$10.8	-$18.0	-$22.7	-$23.9	-$27.7	-$28.4

BOEM has only estimated the quantified benefits of NO_x reductions. The bureau's analysis did not quantify other benefits that are difficult to put a price tag on. ERM may concurrently reduce the emissions of other air pollutants such CO, SO_x and PM, as well, and those reductions would also provide co-benefits and cause an improvement in air quality and a reduction in adverse health and other effects. Additionally, the proposed rule will provide BOEM and affected states improved information on the expected onshore air quality impacts of OCS exploration and development. This improved air emission information would better ensure BOEM only approves plans that meet the requirements of the OCSLA. The proposed rule would strengthen the requirements for identifying, modeling, measuring and tracking the emissions of air pollutants. Coastal states and other stakeholders can thereby be more confident regarding the expected onshore air quality impacts from OCS oil and gas exploration and development. The additional monitoring information required for certain plans will also permit the Bureau of Safety and Environmental Enforcement (BSEE) to better assess the air quality compliance for OCS operations on a plan-by-plan basis.

INITIAL REGULATORY FLEXIBILITY ACT ANALYSIS

The Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities.

Based on this initial analysis, BOEM expects the implementation of this proposed rule to have an economic impact on a substantial number of small entities under 5 U.S.C. 605(b). BOEM, however, is seeking comments on this Initial Regulatory Flexibility Analysis to inform our decision regarding the degree of economic impact of this proposed rule on small entities.

The Regulatory Flexibility Act (RFA) at 5 U.S.C. 603 requires agencies to prepare a regulatory flexibility analysis to determine whether a regulation would have a significant economic impact on a substantial number of small entities. Section 605 of the RFA allows an agency to certify a rule in lieu of preparing an analysis if the regulation is not expected to have a significant economic impact on a substantial number of small entities. Further, under the Small Business Regulatory Enforcement Fairness Act of 1996, 5 U.S.C. 801 (SBREFA), an agency is required to produce compliance guidance for small entities if the rule has a significant economic impact.

The primary components required in an IRFA are found within this broader RIA including the INTRODUCTION AND BACKGROUND, the NEED FOR FEDERAL REGULATORY ACTION and the REGULATORY ALTERNATIVES sections.

Description and Estimated Number of Small Entities Regulated

As defined by the Small Business Administration (SBA), a small entity is one that is “independently owned and operated and which is not dominant in its field of operation.” The definition of small business varies from industry to industry in order to properly reflect industry size differences.

The proposed rule would affect operators and holders of BOEM-issued oil and gas leases that are seeking to explore, develop or transport OCS oil and gas resources. BOEM’s analysis shows that this could include about 130 companies with active operations. Entities that operate under this rule fall under the SBA's North American Industry Classification System (NAICS) codes 211111 (Crude Petroleum and Natural Gas Extraction) and 213111 (Drilling Oil and Gas Wells) or 237120 Oil and Gas Pipeline and Related Structures. For these NAICS classifications, a small company is defined as one with fewer than 500 employees. Based on this criterion, approximately 90 (69 percent) of the 130 companies operating on the OCS are considered small and the remaining are considered large businesses. Therefore, BOEM estimates that the proposed rule would affect a substantial number of small entities.

Of the approximately 130 operators, a total of 56 companies submitted initial, revised, or supplemental exploration/development plans in the Gulf of Mexico during calendar year 2013. BOEM does not have Pacific OCS air quality jurisdiction where six companies operate leases and no small entities are expected to operate in the Arctic within the 10-year window of this analysis. Twenty-four large companies submitted 63 percent of the plans and 32 small companies submitted 37 percent of the plans in the Gulf of Mexico. Operators not submitting EPs, DOCDs and DPPs typically are continuing existing operations or holding leases undergoing geological and geophysical prospecting.

Description and Estimate of Compliance Requirements

An exploration or development plan is the preliminary application before companies explore for hydrocarbons on the OCS or develop an economic prospect. All companies operating on the OCS including small entities must be well capitalized to undertake these multi-million or multi-billion dollar projects. The incremental cost for providing additional or consolidated air quality information for exploration plans, DOCDs or DPPs is a small cost in the context of an exploration or development project. Most of the compliance costs imposed as a result of this rulemaking are variable costs directly dependent on the complexity and number of EPs, DOCDs and DPPs submitted. Emissions reduction measure costs would be directly related to the impact a project may have on a state's air quality. BOEM's first-order estimate for the rulemaking's small entity compliance costs is proportional to the number of plans submitted excluding BACT costs.

The compliance costs from this rulemaking may be less for most small entities because these companies are less likely to operate the large projects that employ multiple MODUs drilling concurrently. If a facility or project is located close to the federal/state submerged lands boundary shows emissions above the SILs and is operated or owned by a small entity, this proposed rule could have a significant economic impact. The GOM shelf is a mature hydrocarbon environment and few companies are initiating new exploration or development projects. However, the GOM shelf is where most of the small entities operate and hold leases. While most of the compliance costs would be imposed on lessees and operators of large deepwater projects, some near-shore projects may be impacted.

Using 2013 as a base, small companies submit about 37 percent of the plans each year and are expected to incur approximately the same proportion of costs. The incremental first year compliance costs for this rulemaking are projected to be $23 million and the peak year is $49 million. Some of those costs are for ERM or emissions credits on a very small number of projects which may or may not be owned or operated by small entities. The modeling, reporting and other costs range from $7 to $28 million each year and small entities operating in the GOM are estimated to incur a similar proportion (37 percent) of costs in each subsequent year -- about $3 million in the first year and $10 million in the 10th year. No small entities are expected to operate in the Arctic within the 10-year window of this analysis.

This incremental modeling and reporting costs for this rulemaking will generally be required of both the larger deepwater projects and near shore projects. While there are smaller companies that explore and operate in deeper water, these companies are well capitalized and the incremental compliance costs for this rulemaking are estimated to be minimal when compared to the cost of drilling a single deepwater well.

Based on this analysis, BOEM concludes that this proposed rule may have a significant economic impact on a substantial number of small entities. BOEM is requesting comment on the costs and impacts of the proposed policies in this rule on small entities. We will consider all comments at the final rule stage. We specifically request comments on the compliance cost estimates as well as regulatory alternatives that would reduce the burden on small entities.

Alternatives Considered

The REGULATORY ALTERNATIVES section provides six regulatory alternatives considered by BOEM. The proposed rule protects state air quality with an ample margin of safety. The provisions are designed to safeguard the public and BOEM does not believe that exceptions are defensible for small entities.

In its consideration of the regulatory alternatives as well as in its specific formulation of the proposed rule, BOEM has been aware of the potential for impacts on small entities and has designed a rule that accommodates the needs of small entities as far as is consistent with the objective of the regulation. BOEM believes the proposed rule offers the least burdensome method to ensure regulatory compliance with the NAAQS. Exempting small entities from provisions would pose an unreasonable risk. The proposed rule provides flexibility for emission reduction measures for all companies including small entities. Modeling and other air emissions information is necessary for BOEM to only approve plans that would not generate emissions causing state air quality to exceed the NAAQS. BOEM is not proposing the monitoring of actual emissions in most cases, but only submission of monthly fuel and activity records for estimating emissions. The monitoring information is necessary for BSEE to confirm reasonable compliance with the approved emissions in the plan.

BOEM welcomes comments on alternative regulatory provisions it has not analyzed. Feedback is sought on more cost-effective regulatory alternatives that would provide the same or greater protection of state air quality.

Other Federal Rules that Overlap or Conflict with Proposed Rule

Congress has delegated to DOI jurisdiction for ensuring air compliance with the NAAQS pursuant to the CAA, to the extent that activities authorized under OCSLA significantly affect the air quality of any State. This includes OCS areas adjacent to Texas, Louisiana, Mississippi, Alabama, and the North Slope Borough of the State of Alaska. There is no overlap of the areas regulated by BOEM and those regulated by the USEPA or States under the CAA.

BOEM has traditionally relied on the EPA's AQS data to determine the relevant ambient air quality required by lessees and operators to perform their analysis of the AAIs and the NAAQS in connection with their submission of plans and to comply with BOEM's air quality requirements in areas under BOEM's air quality jurisdiction. BOEM does not intentionally request original or duplicative data from operators.

The proposed rule would be consistent with BOEM's current efforts to coordinate with USEPA and state regulation under the CAA. It would codify the existing mechanism BOEM uses in the Gulf of Mexico (GOM) OCS Region to report ongoing emissions information (i.e., the Gulf-wide Offshore Activities Data System or GOADS. BOEM shares these data with USEPA to enhance its national emissions inventory, with States and local management agencies to improve air quality, and with States to develop State Implementation Plans (SIPs). In addition, this information is important to ensure that OCS activities that BOEM authorizes do not cause any state to exceed the NAAQS. BOEM also uses this information in its National Environmental Policy Act (NEPA) documents at several stages of the OCS leasing and plan review and approval process.

The USEPA requires the reporting of certain emissions such as the Greenhouse Gas Reporting Rule (74 FR 56260) which requires reporting of greenhouse gas (GHG) data and other relevant information from large sources and suppliers in the United States. For Operators and Lessees that are subject to reporting under the Greenhouse Gas Reporting Program (GHGRP) BOEM collects emissions information related to GHGs on a regular basis as part of the GOADS program and provides this information to lessees and operators to facilitate their reporting to the USEPA.

Although having one set of requirements for both BOEM and the USEPA might be administratively convenient, BOEM's mandate to evaluate the impacts of OCS emissions on the air quality of States does not necessitate this practice. Additionally, the under OCSLA, BOEM is required to take action regarding a plan within 30 or 60 days, depending on the type of plan, if it is found to be consistent with OCSLA and its implementing regulations, including those ensuring air quality compliance under section 5(a)(8) of OCSLA. (See 43 U.S.C. sections 1340(c) and 1351(h)). These timeframes would not permit BOEM to adopt all of the USEPA's requirements.

BOEM welcomes comments on potentially duplicative, overlapping or conflicting provisions in this rule it has not analyzed. The Small Business and Agriculture Regulatory Enforcement Ombudsman and 10 Regional Fairness Boards were established to receive comments from small businesses about Federal agency enforcement actions. The Ombudsman will annually evaluate the enforcement activities and rate an agency's responsiveness to small business. If you wish to comment on the actions of BOEM, call 1-888-734-3247. You may comment to the Small Business Administration without fear of retaliation. Allegations of discrimination/retaliation filed with the Small Business Administration will be investigated for appropriate action.

EXECUTIVE ORDER 13211 Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use

Under Executive Order 13211, agencies are required to prepare and submit to OMB a Statement of Energy Effects for significant energy actions. Section 4(b) of Executive Order 13211 defines a "significant energy action" as any action by an agency (normally published in the Federal Register) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking:

(i) that is a significant regulatory action under Executive Order 12866;
(ii) that is likely to have a significant adverse effect on the supply, distribution, or use of energy; or
(iii) that is designated by the Administrator of OIRA as a significant energy action.

BOEM has determined this rule is not a significant energy action under the definition in Executive Order 13211.

The increased air quality regulatory cost theoretically could lead to an increase in the minimum field size considered economically viable. Stated another way, the reservation price for developing marginal prospects could increase as the result of this proposed regulation, thereby jeopardizing the economic viability of marginally valued projects. This situation can be expected to occur more frequently when GOM hydrocarbons are located where modeling shows the air emissions from the project may adversely affect the air quality of a State or a Class I area. In those cases, the added project costs and associated implications for potential project viability arise if the project is required to implement selective catalytic reduction BACT for NOx under the provisions of this proposed rule, but not under the regulatory baseline. These requirements would potentially apply more often for projects of any size located close to shore or of large size and located up to 100 miles from shore.

Incremental SCR BACT expense of between two and three percent of drilling and completion costs could theoretically render some marginally profitable projects potentially uneconomic in the short-term. This is most likely if the marginal prospect is especially close to shore or predominantly a gas prospect. As a rule of thumb, drilling and completion expenses are about 40 to 45 percent of the cost for an offshore development project. So, if SCR BACT was the only viable reduction option, there could be some, but probably few if any, near shore OCS projects that are made unprofitable by this rulemaking.

However, the emissions credits option in § 550.309(e)(4) provides that an operator can utilize emissions reductions procedures for the period of time sufficient to ensure a plan's continued compliance with the regulations. This allows projects to procure emissions credits for only the exceedance period rather than for the entire duration of the project. This provision should both protect the NAAQS and prevent any otherwise economically profitable projects from being rendered uneconomic by this rulemaking.

Even so, the future production of a marginally profitable prospect potentially rendered uneconomic due to this proposed regulation would not be lost forever. When air emissions control technology becomes more cost effective, or hydrocarbon prices increase, the discovered hydrocarbons could remain available for economic development, albeit at higher cost, especially if the existing infrastructure remains intact. Where modeling shows impacts to state air quality above the SILs, the bureau expects few if any potentially affected GOM projects to be economically marginal. For these reasons, it is most likely that no project will either be forced to shut down or even delayed in starting up as a result of this rulemaking over the 10-year window of this analysis.

EXECUTIVE ORDER 13563: Employment Impact Analysis

Executive Order 13563 reaffirms the principles established in Executive Order 12866, but calls for additional consideration regarding the regulation's impact on employment. It states, "Our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation." An analysis of employment impacts is a standalone analysis and the impacts are not included in the estimation of benefits and costs.

The primary interest is the extent to which the regulatory burden imposed by this proposed rule may change operators' OCS investment decisions. If the economic burden is not significant and all other factors are equal, then one would expect operators to maintain existing levels of investment and employment. In this instance, all other factors are not necessarily equal. For example, investment in the GOM has recently weakened due to a lower price environment. As a result of these market conditions, companies involved in offshore exploration and those that service those companies have made significant employment cuts. These employment impacts are separate and unique from the possible impacts of the proposed rule.

The proposed rule would require all OCS operators to report additional information in their plans and report ongoing information regarding activities of their operations. It would require most operators to conduct additional modeling and analysis of plan air emissions. A few operators may be required to employ ERMs or purchase emissions credits for projects that could impact the air quality impacts on an affected state. Consistent with the discussion in the Energy Effects analysis, BOEM believes this proposed rule is unlikely to result in lessees foregoing investments in marginal economic oil and gas development projects. To the extent that these would negatively impact employment, BOEM does not expect significant impacts.

Although the proposed rule could potentially reduce employment among companies involved in drilling and exploration, some companies are likely to benefit from the regulation. For example, consulting firms specializing in air quality analysis and modeling are likely experience increased employment demand. As more companies need to model and maintain records of their emissions, new employment opportunities in the broad field of air quality analysis will emerge. While BOEM does not anticipate that many companies will adopt an emissions reduction measure like post-combustion SCR, the companies that install these mitigation technologies would benefit from increased demand for their equipment.

The proposed rule is not expected to generate either large negative or positive employment impacts. On balance, there will likely be adjustments on both sides among companies directly and indirectly affected by the regulation.

BOEM seeks comments on the range of employment impacts that may occur as a result of the proposed rule. Specifically, BOEM solicits comments on the proposed changes in the regulation that would require plans to include BACT. Also, note that pending EPA standard changes for the 1-hour NOx SIL and ozone modeling requirements are expected to increase operator costs, but are not subject to BOEM's regulatory discretion.

UNFUNDED MANDATES REFORM ACT (UMRA)

This rule does not impose on State, local or Tribal governments, or the private sector, an unfunded mandate of more than $100 million per year. The rule does not have a significant or unique effect on State, local or Tribal governments, or the private sector. A statement containing the information required by UMRA (2 U.S.C. §§ 1531*et seq.*) is not required.