Oil and Gas and Sulphur Operations in the Outer Continental Shelf – Blowout Preventer Systems and Well Control

Initial Regulatory Impact Analysis

RIN: 1014-AA11

NOTICE OF PROPOSED RULEMAKING

DEPARTMENT OF THE INTERIOR

Bureau of Safety and Environmental Enforcement

30 CFR Part 250

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1. Introduction

Changes to Federal regulations must undergo several types of economic analyses. First, Executive Orders (E.O.) 13563 and 12866 direct agencies to assess the costs and benefits of available regulatory alternatives and, if regulation is necessary, select a regulatory approach that maximizes net benefits (including potential economic, environmental, public health, and safety effects; distributive impacts; and equity). E.O. 13563 emphasizes the importance of quantifying both costs and benefits, reducing costs, harmonizing rules, and promoting flexibility. Under E.O. 12866, an Agency must determine whether a regulatory action is significant and, therefore, subject to the requirements of the E.O. and review by the Office of Management and Budget (OMB). Section 3(f) of E.O. 12866 defines a "significant regulatory action" as any regulatory action that is likely to result in a rule that:

(a) Has an annual effect on the economy of $100 million or more, or adversely affects in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities (also referred to as "economically significant");

(b) Creates serious inconsistency or otherwise interferes with an action taken or planned by another agency;

(c) Materially alters the budgetary impacts of entitlement grants, user fees, loan programs, or the rights and obligations of recipients thereof; or

(d) Raises novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in E.O. 12866.

The proposed rule is a "significant regulatory action" that is economically significant under section 3(f)(1) of E.O. 12866. Accordingly, OMB has reviewed this regulation.

Second, the Regulatory Flexibility Act (RFA) of 1980 requires agencies to consider the economic impact of regulatory changes on small entities. Finally, the Unfunded Mandates Reform Act of 1995 (UMRA) (Public Law 104-4) requires agencies to prepare a written assessment of the costs, benefits, and other effects of proposed or final rules that include a Federal mandate likely to result in the aggregate expenditure of $100 million or more annually (adjusted for inflation) by state, local, or tribal governments or by the private sector.

In conducting these analyses on the proposed rule, the Bureau of Safety and Environmental Enforcement (BSEE) provides the following summary:

(1) BSEE has determined that the proposed rule is a significant rulemaking within the definition of E.O. 12866 because the estimated annual costs or benefits exceed $100 million in at least one year of the 10-year analysis period;

(2) BSEE has determined that the proposed rule would have a "significant economic impact on a substantial number of small entities" under section 605(b) of the RFA; and

(3) BSEE has determined that the proposed rule would not impose an unfunded mandate on State, local, or tribal governments as defined by the UMRA. We have determined that the proposed rule, if finalized, would impose a Federal mandate that may result in the expenditure by the private sector of $100 million or more (adjusted annually for inflation) in a given year.

2. <u>Need for regulation</u>

BSEE identified a need to amend the existing Blowout Preventer (BOP) and well-control regulations to enhance the safety and environmental protection of oil and gas operations on the OCS. In particular, BSEE considers the proposed rule necessary to reduce the likelihood of any oil or gas blowout, which can lead to the loss of life, serious injuries, and harm to the environment. As was evidenced by the *Deepwater Horizon* incident (which began with a blowout at the Macondo well) on April 20, 2010, blowouts can result in catastrophic consequences.[1] Government and industry conducted multiple investigations to determine the cause of the *Deepwater Horizon* incident; many of these investigations identified BOP performance as a concern. BSEE convened Federal decision-makers and stakeholders from the OCS industry, academia, and other entities at a public forum on offshore energy safety on May 22, 2012, to discuss ways to address this concern. The investigations and the forum resulted in a set of recommendations to improve BOP performance.

As the agency charged with oversight of offshore operations conducted on the OCS, BSEE seeks to improve safety and mitigate risks associated with such operations. After careful consideration of the various investigations conducted after the *Deepwater Horizon* incident and industry's responses to the incident, BSEE has determined that the requirements contained in this proposed rule are critical to address risks associated with offshore operations. BSEE determined that the BOP regulations need to be updated to incorporate some of the more pertinent recommendations, while others are being studied for consideration in future rulemakings. The Proposed Rule would create a new Subpart G in 30 CFR Part 250 to consolidate the requirements for drilling, completion, workover, and decommissioning operations. Consolidating these requirements would improve efficiency and consistency of the regulations and allow for flexibility in future rulemakings. The Proposed Rule would also revise existing provisions throughout Subparts D, E, F, and Q to address concerns raised in the investigations, BSEE's internal reviews, and the public forum. Finally, the Proposed Rule would incorporate American Petroleum Institute (API) Standard 53 to ensure better BOP operability and more robust regulatory oversight.

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[1] For example, any approximation of cost would incorporate catastrophic spills such as the *Deepwater Horizon* incident. The cost to BP of cleanup operations for the *Deepwater Horizon* incident has been estimated at more than $14 billion. In addition to cleanup costs, BP has paid over $14 billion to Federal, State, and local governments as well as private parties for economic claims and other expenses. Source: Ramseur, J.L., Hagerty, C.L. 2014. "Deepwater Horizon Oil Spill: Recent Activities and Ongoing Developments," Congressional Research Office. Available at: http://www.fas.org/sgp/crs/misc/R42942.pdf.

3. Alternatives

BSEE has considered three regulatory alternatives:

(1) Promulgate the requirements contained within the proposed rule, including increasing the BOP testing frequency for workover and decommissioning operations from the current requirement of once every 7 days to the proposed requirement of once every 14 days . The following chart identifies the BOP testing changes related to Alternative 1;

BOP Pressure Testing		
Operation	**Current Testing Frequency**	**Proposed Testing Frequency**
Drilling / Completions	Once every 14 days	Once every 14 days
Workover / Decommissioning	Once every 7 days	Once every 14days

(2) Promulgate the requirements contained within the proposed rule with a change to the required frequency of BOP pressure testing from the existing regulatory requirements (*i.e.,* once every 7 or 14 days depending upon the type of operation) to once every 21 days for all operations. The following chart identifies the BOP testing changes related to alternative 2;

BOP Pressure Testing			
Operation	**Current Testing Frequency**	**Proposed Testing Frequency (Alternative 1)**	**Alternative 2 Testing Frequency**
Drilling / Completions	Once every 14 days	Once every 14 days	Once every 21 days
Workover / Decommissioning	Once every 7 days	Once every 14 days	Once every 21 days*

* includes change from current 7 days to proposed 14 days

(3) Take no regulatory action and continue to rely on existing BOP regulations in combination with permit conditions, Deep Water Operations Plans (DWOPs), operator prudence, and industry standards.

By taking no regulatory action, BSEE would leave unaddressed most of the concerns and recommendations that were raised[2] regarding the safety of offshore oil and gas operations and the potential for another event with consequences similar to those of the *Deepwater Horizon* incident.

Alternative 2 was not selected because BSEE is lacking critical data on testing frequency and equipment reliability. This issue may be considered in the final rulemaking if BSEE receives sufficient data to support alternative 2.

BSEE has elected to move forward with Alternative 1--the proposed rule--which incorporates recommendations provided by government, industry, academia, and other stakeholders as well as API Standard 53. In addition to addressing concerns and aligning with industry standards, BSEE is functioning in a prudent capacity with this proposed rule by advancing several of the more critical capabilities beyond current industry standards based on internal knowledge and experience. The proposed rule would also improve efficiency and consistency of the regulations and allow for flexibility in future rulemakings.

BSEE is requesting comments on how long it would take to come into compliance with the proposed rule as well as any other alternatives BSEE may reasonably consider, including alternatives to the specific provisions contained in the Notice of Proposed Rulemaking (NPRM).

4. <u>Economic analysis</u>

BSEE's economic analysis evaluated the expected impacts of the proposed rule compared with the baseline. The baseline refers to current industry practice in accordance with existing regulations,

[2] *See* the DOI JIT report "Report Regarding the Causes of the April 20, 2010 Macondo Well Blowout," September 14, 2011; the National Commission final report, "Deep Water, The Gulf Oil Disaster and the Future of Offshore Drilling," January 11, 2011; the Chief Counsel for the National Commission report, "Macondo The Gulf Oil Disaster," February 17, 2011,; the National Academy of Engineering final report, " Macondo Well-*Deepwater Horizon* Blowout," December 14, 2011; BSEE public offshore energy safety forum, May 22, 2012.

industry permits, DWOPs, and industry standards with which operators already comply.[3] Impacts that exist as part of the baseline were not considered costs or benefits of the proposed rule. Specifically, the analysis excluded activities or capital investments that are required by existing regulations or as conditions for permit or DWOP approval. The analysis also excluded impacts resulting from the incorporation of industry standards with which operators already comply. Thus, the cost analysis evaluates only activities and capital investments required by the proposed rule that represent a change from the baseline.

This section provides an overview of the analysis of costs, benefits, and transfers, as well as the assumptions used in the analysis. The methodology for the costs and benefits analysis is described in more detail in subsequent sections. BSEE requests comment on the analysis, including potential sources of data or information on the benefits and costs of the proposed rule.

a. Costs

Section 5 below outlines how we quantified and monetized the potential costs of the proposed rule. It identifies all of the provisions that would result in increased labor requirements or capital investments for industry or costs to BSEE. In addition to the new regulatory requirements, we also considered the time required of industry staff to read and familiarize themselves with the new regulation. For the purpose of transparency, we include footnotes presenting the information on data inputs and the details of the cost calculations for each rule provision.

[3] BSEE considers compliance with permits, DWOPs, and industry standards to be "self-implementing," as addressed in Section E.2 of OMB Circular A-4, "Regulatory Analysis" (2003), and thus includes these costs in the baseline for the economic analysis. Each industry standard comes from a committee of industry members who develop and vet each of the provisions written in the standards. We are not aware of industry standards that some operators do not follow.

The analysis covers 10 years (2015 through 2024) to ensure it encompasses the significant costs and benefits likely to result from the proposed rule. A 10-year analysis period was used for this analysis because of the uncertainty associated with predicting industry's activities and the advancement of technical capabilities beyond 10 years. The regulated community itself finds it challenging to engage in business modeling beyond a 10-year time frame due to market volatility around oil pricing. Over time, the costs associated with a particular new technology may drop because of various supply and demand factors, causing the technology to be adopted more broadly. In other cases, an existing technology may be replaced by a lower-cost alternative as business needs drive technological innovation. Extrapolating costs and benefits beyond this 10-year time frame would produce more ambiguous results and therefore be disadvantageous in determining actual costs and benefits likely to result from this proposed rule. BSEE concluded that this 10-year analysis period provides the best overall ability to forecast costs and benefits likely to result from this proposed rule. To summarize the costs of specific provisions, we present the estimated average annual cost as well as 10-year discounted totals to estimate the present value of the costs. In accordance with OMB guidance on conducting regulatory analysis (OMB Circular A-4, "Regulatory Analysis," 2003), we used discount rates of 3 and 7 percent to calculate the discounted net present value of the proposed rule.

BSEE is considering requiring operators to install technology capable of severing any components of the drill string (excluding drill bits) within 10 years of the effective date of the rule. However, this provision's important costs are inherently difficult to quantify or monetize given available data. For example, the identification of impacts potentially caused by failures to comply with this potential provision would require highly speculative assumptions principally because the impacts of such compliance failures could range from record-keeping violations to full well-bore discharges from submerged OCS lands situated in deep water.[4] Additionally, to the extent such risks exist, their magnitude is unknown. For these reasons, BSEE is unable to monetize or quantify these costs. BSEE is aware of at least one candidate technology that is currently being evaluated and believes that there are other possible innovative technologies that may be available to accomplish these objectives within the time horizon pertinent to this provision. As also discussed in the preamble to the proposed rule, BSEE requests comments on associated costs related to this potential provision.

b. Benefits

Section 6 below presents the data, methodology, and results of the benefits analysis. We quantified and monetized the potential benefits of the proposed rule, including time savings, reduction in oil spills, and reduction in fatalities. We estimated the benefits derived from time savings associated with proposed section 250.737(d)(10) of the proposed rule, which would streamline the BOP testing. We also estimated time-savings benefits associated with a change in the required frequency of BOP pressure testing under Alternative 2, which would reduce the number of required BOP pressure tests per year. In addition, we estimated the benefits derived from the reduction in oil spills and fatalities using the incident-reducing potential of the proposed rule as a whole.

We calculated the benefits under various risk-reduction scenarios, which allowed us to determine the cost-effectiveness of the proposed rule (*i.e.*, whether the benefits justified the costs) depending on the percentage of potential oil spills and number of fatalities potentially prevented. In addition, we conducted sensitivity analysis on the price of a barrel of oil to reflect recent price fluctuations. Similar to

[4] For example, any approximation of cost would incorporate catastrophic spills such as the *Deepwater Horizon* incident. The cost to BP of cleanup operations for the *Deepwater Horizon* incident has been estimated at more than $14 billion. In addition to cleanup costs, BP has paid over $14 billion to Federal, State, and local governments as well as private parties for economic claims and other expenses. Source: Ramseur, J.L., Hagerty, C.L. 2014. "Deepwater Horizon Oil Spill: Recent Activities and Ongoing Developments," Congressional Research Office. Available at: http://www.fas.org/sgp/crs/misc/R42942.pdf.

the costs analysis, we estimated the potential benefits over a 10-year study period (2015 through 2024). The benefits are presented as 10-year discounted totals, that is, the present value of the benefits.

c. Transfers

We did not identify any transfer payments associated with the proposed rule. Transfer payments, as defined by OMB Circular A-4, “Regulatory Analysis,” (2003) are payments from one group to another that do not affect total resources available to society.

d. Data inputs

We estimated costs and benefits presented in this document using various data inputs. Some of these data inputs were common to many of the calculations, including the assumptions about affected population, wage rates and loaded wage factors, and daily rig operating costs, as explained below.

i. Affected population

We estimated that a total of 90 rigs would be affected by the proposed rule, including 40 subsea BOP rigs and 50 surface BOP rigs, based on the current number of operational rigs on the OCS. We also estimated that 320 wells are drilled per year with an average of three wells per rig. Due to the fluctuating nature of activity on the OCS, for the purposes of analysis we assumed that the number of operating wells and rigs would remain constant over the 10-year analysis period. BSEE seeks comment on whether these estimates are accurate.

ii. Wage rates and loaded wage factors

Many of the calculations in this analysis used wage rates for OCS oil and gas or BSEE employees. We estimated average industry wage rates for the following labor categories: mid-level industry engineer, administrative staff, rig crew staff (*e.g.*, roughneck, floorman, tool-pusher, subsea engineer), and technician. We estimated the average hourly wage rate of $62.24 for a mid-level industry engineer based on the median wage rate for a petroleum engineer in the United States as reported by the Bureau of Labor Statistics (BLS). We based the average hourly wage rate of $21 for an administrative staff on the wage rate for a clerical employee provided in BSEE's Supporting Statement A (BSEE Production Safety Systems). We estimated the average hourly wage rates of $40 for a rig crew staff person and a technician based on BSEE's knowledge of the industry.

We also estimated the average wage rates for BSEE personnel for a mid-level BSEE engineer and for clerical staff. We estimated the average hourly wage rate for a mid-level BSEE engineer to be $41.52 using data from the OPM: GS-12, step 5 average wage rate for the Houston metropolitan statistical area and the parishes of Jefferson, Lake Charles, and Houma in Louisiana. We estimated the average hourly wage rate for a clerical staff to be $22.41 using OPM data by averaging the GS-7, step 5 wage rates for the Houston metropolitan statistical area and for the rest of the United States.

To account for employee benefits, we multiplied average hourly wage rates by an appropriate loaded wage factor to generate average hourly compensation rates. For the OCS industry, we used a private sector loaded wage factor of 1.42 derived from the 2012 BLS index for salary and benefits. For BSEE positions, we used a Federal loaded wage factor of 1.69 derived from a U.S. Department of Labor analysis of overhead costs (in the absence of a similar estimate for BSEE).[5] We multiplied the average hourly wage rates by the appropriate loaded wage factor to estimate the following average hourly compensation rates:

- $88.38 for a mid-level industry engineer;
- $29.82 for an industry administrative staff;

[5] The 1.69 index is derived by using BLS index for salary and benefits plus the Department of Labor's analysis of overhead costs averaged over all employees of the agency.

- $56.80 for an industry rig crew staff;
- $56.80 for an industry technician;
- $70.17 for a mid-level BSEE engineer; and
- $37.87 for a BSEE clerical staff.

iii. Daily rig operating costs

Some requirements in the proposed rule affect rig operations. To monetize the impacts of these requirements, we estimated the daily rig operating costs for affected rigs. Based on input from BSEE and industry subject matter experts, we assumed that subsea BOP rigs have a daily rig operating cost of $1 million and surface BOP rigs have a daily rig operating cost of $200,000. We recognize that these figures can fluctuate and thus have chosen estimates that reflect the average daily rig operating costs for those with surface and subsea BOPs (*i.e.*, $200,000 and $1 million, respectively[6]). BSEE requests comment on these values for consideration at the Final Rule stage. For the purposes of the analysis, we assumed that the daily rig operating costs remain constant over the 10-year analysis period.

5. Section-by-section analysis of costs

The economic analysis presented in this document evaluated the expected impacts of the proposed rule compared to the baseline (*i.e.*, current practice in accordance with existing BOP regulations, industry permits, DWOPs, and API industry standards with which industry already complies). Alternative 2 results in a time-savings benefit to industry but no additional costs to industry, and thus the costs presented below are the same for Alternatives 1 and 2. The following proposed requirements would result in a change from the baseline:

[6] BSEE based the daily rig operating costs in part upon industry listings of rig day rates (*see, e.g.*, http://www.rigzone.com/data/dayrates/), consultation with the Bureau of Ocean Energy Management economists, and review of previously approved rates in published rulemakings. We assume that the daily cost estimate includes both the daily operating costs of the rig and of the personnel that support those daily activities. BSEE is inviting comments on those cost estimates and assumptions.

(a) Additional information in the description of well drilling design criteria;

(b) Additional information in the drilling prognosis;

(c) Prohibition of a liner as conductor casing;

(d) Additional capping stack testing requirements;

(e) Additional information in the Application for Permit to Modify (APM) for installed packers;

(f) Additional information in the APM for pulled and reinstalled packers;

(g) Rig movement reporting;

(h) Fitness requirements for Mobile Offshore Drilling Units (MODUs) and lift boats;

(i) Foundation requirements for MODUs and lift boats;

(j) Monitoring of well operations with a subsea BOP;

(k) Additional documentation and verification requirements for BOP systems and system components;

(l) Additional information in the Application for Permit to Drill (APD), APM, or other submittal for BOP systems and system components;

(m) Submission by the operator of a Mechanical Integrity Assessment Report completed by a BSEE-approved verification body;[7]

(n) New surface BOP system requirements;

[7] The approved verification organization would have to submit documentation for approval by BSEE describing the organization's applicable qualification and experience. See discussion on Third-party Verification in the NPRM for further information.

(o) New subsea BOP system requirements;

(p) New surface accumulator system requirements;

(q) Chart recorders;

(r) Notification and procedures requirements for testing of surface BOP systems;

(s) Alternating BOP control station function testing;

(t) Remote operated vehicle (ROV) intervention function testing;

(u) Autoshear, deadman, and emergency disconnect system (EDS) function testing on subsea BOPs;

(v) Approval for well control equipment not covered in Subpart G;

(w) Breakdown and inspection of BOP system and components;

(x) Additional recordkeeping for real-time monitoring; and

(y) Industry familiarization with the new rule.

These proposed requirements and their associated costs to industry and government are presented in the sections that follow.

a. <u>Additional information in the description of well drilling design criteria</u>

Section 250.413(g) in the proposed rule would require information on the equivalent circulating density (ECD) to be included in the description of the well drilling design criteria. The ECD is an important parameter in avoiding fracturing the formation or compromising the casing shoe integrity, which could lead to erratic pressures and uncontrolled flows (*e.g.*, formation kicks) emanating from a well reservoir during drilling. This information is necessary to better review the well drilling design and drilling program.

The requirement to include information on the ECD in the well drilling design criteria would result in increased labor costs for industry. We calculated the annual industry labor cost associated with this new requirement by multiplying the time required per well to include the additional information in the well drilling criteria by the average hourly compensation rate for the staff most likely to complete this task. We then multiplied this product by the expected number of wells drilled per year, resulting in an estimated annual labor cost to industry for this documentation requirement of $28,282.[8] No additional costs to BSEE are expected as a result of this proposed requirement.

b. Additional information in the drilling prognosis

Section 250.414 would require industry to provide additional information in the drilling prognosis. New paragraph (j) would require the drilling prognosis to identify the type of wellhead system to be installed with a descriptive schematic, which should include pressure ratings, dimensions, valves, load shoulders, and locking mechanism, if applicable. This information would provide BSEE with data to reference during the approval process and would enable industry and BSEE to confirm that the wellhead system is adequate for the intended use.

The requirement to include additional information in the drilling prognosis would result in increased annual labor costs to industry. BSEE considers the additional information required for the drilling prognosis (submitted as part of the APD) to be readily available. We calculated the annual labor cost for

[8] We assumed that industry staff (mid-level engineer) would spend one hour per well to include the additional information in the well drilling design criteria. Industry already complies with this new requirement as part of its design practice for most wells drilled. We assumed that this requirement would result in a new cost for all wells drilled per year (320). We multiplied the number of industry staff hours per well by the average hourly compensation rate for a mid-level industry engineer ($88.38) and the average number of wells drilled per year to obtain an average annual labor cost to industry of $28,282 (1 x $88.38 x 320).

this activity by multiplying the time required to gather and document the information by the average hourly compensation rate of the staff most likely to complete this task. We then multiplied the product of this calculation by the estimated number of wells drilled per year, resulting in an estimated annual labor cost to industry for this documentation requirement of $7,070.[9] No additional costs to BSEE are expected as a result of this proposed requirement.

c. Prohibition of a liner as conductor casing

Section 250.421(f) would be revised to no longer allow a liner to be installed as conductor casing. This would ensure that the drive pipe is not exposed to wellbore pressures during drilling in subsequent hole sections.

This provision would result in an annual equipment and labor cost to industry for wells that are currently allowed to use a liner as conductor casing. We multiplied the average cost of the casing joints and wellhead per well by the number of affected wells in order to calculate annual equipment installation costs. To calculate the associated annual labor costs, we multiplied the time required to install the equipment per well by the daily labor cost of rig crew time and by the number of wells on which the equipment must be installed. We then summed the equipment and labor costs to estimate the average annual equipment and labor cost to industry for this requirement of $795,000.[10] No additional costs to BSEE are expected as a result of this proposed requirement.

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[9] We assumed that industry staff (a mid-level engineer) would spend 0.25 hours to include the additional information in the drilling prognosis for a well. We multiplied the number of industry staff hours per well by the average hourly compensation rate for a mid-level industry engineer ($88.38) and the average number of wells drilled per year (320) to obtain the average annual labor cost to industry of $7,070 (0.25 x $88.38 x 320).

[10] We estimated that approximately one percent of drilled wells currently have a liner as conductor casing (approximately one percent of 320 wells, or three wells), based on input provided in submittals to BSEE. In order to calculate the average annual equipment costs, we assumed that the average cost of the casing joints and wellhead per well would be $65,000. We multiplied the equipment cost per well by the number of affected wells to yield an average equipment cost of $195,000 ($65,000 x 3). We assumed that industry staff (rig crew) would spend one day to install the new equipment on a well. We then multiplied the number of industry staff days per

d. Additional capping stack testing requirements

Section 250.462 would address source control and containment requirements. New paragraph (e)(1) would detail requirements for testing of capping stacks. New requirements include the function testing of all critical components on a quarterly basis and the pressure testing of pressure holding critical components on a bi-annual basis. Under current regulations, there is no testing requirement for capping stacks. These new requirements would help ensure that operators are able to contain a subsea blowout.

These new testing requirements would result in new equipment and service costs to industry. We estimated the cost of testing for each capping stack and multiplied this cost by the total number of anticipated tests to be performed. These calculations resulted in annual compliance costs to industry associated with these requirements of $80,000.[11] No additional costs to BSEE are expected as a result of these proposed requirements.

e. Additional information in the APM for installed packers

In Section 250.518, proposed paragraphs (e) and (f) would clarify requirements for installed packers and bridge plugs and require additional information in the APM, including descriptions and calculations for determining production packer setting depth. These proposed new requirements would codify existing BSEE policy to ensure consistent permitting. It is expected that operators already comply with the proposed design specifications included in this section because this is the only established industry

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well by the average labor cost for a rig crew per day ($200,000) and by the number of affected wells to obtain an estimated average annual labor cost to industry of $600,000 ($200,000 x 3) for this requirement. Summing the equipment and labor costs yields a total average annual cost to industry of $795,000 for this requirement.

[11] We assumed that the quarterly equipment and service costs of testing for capping stacks would be $5,000 per test. BSEE requests comments on the reasonableness of this estimate. Additionally, we assumed that 4 capping stacks would be tested quarterly (or a total of 16 annual tests performed). We multiplied the costs per test by the number of annual tests in order to determine a total annual equipment and service cost to industry of $80,000 (16 x $5,000). We assumed that the required testing would occur at the storage site of the capping stack and we thus do not anticipate costs for time diverted from normal rig operations as a result of this requirement.

standard. Thus, the depth setting calculation is the only requirement that would impose a new cost beyond the baseline. The required calculations would be submitted for every well that is completed where tubing is installed.

The proposed requirement to include additional information in the APM would result in a labor cost to industry and BSEE. To calculate the industry labor cost associated with this new requirement, we multiplied the time required to add the new descriptions and calculations to an APM by the average hourly compensation rate of the industry staff most likely to complete this task and by the number of wells with installed packers for which an APM would be submitted per year. To calculate the new annual labor cost to BSEE, we multiplied the time that BSEE would spend reviewing the new information in an APM by the average hourly compensation rate of the BSEE staff most likely to complete this task and by the number of wells with installed packers for which an APM would be submitted each year. We estimated an average annual labor cost for this proposed documentation requirement of $5,745 to industry and $4,561 to BSEE.[12]

f. Additional information in the APM for pulled and reinstalled packers

In Section 250.619, proposed new paragraphs (e) and (f) would clarify requirements for pulled and reinstalled packers and bridge plugs and require additional descriptions and calculations in the APM regarding production packer setting depth. These proposed new requirements would codify existing

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[12] We assumed that industry staff (a mid-level engineer) would spend 0.25 hours to include the additional information in the APM for a well. We assumed that APMs would be submitted for an average of 260 wells with installed packers per year. We multiplied the number of industry staff hours per well by the average hourly compensation rate for a mid-level industry engineer ($88.38) and by the estimated number of wells with installed packers for which an APM would be submitted per year to obtain an estimated average annual labor cost to industry of $5,745 (0.25 x $88.38 x 260). We assumed that BSEE staff (a mid-level engineer) would spend 0.25 hours to review the additional information in the APM for a well. We multiplied the number of BSEE staff hours per well by the average hourly compensation rate for a mid-level BSEE engineer ($70.17) and by the estimated number of wells with installed packers for which an APM would be submitted per year to obtain an average annual labor cost to BSEE of $4,561 (0.25 x $70.17 x 260).

BSEE policy to ensure consistent permitting. It is expected that operators already comply with the design specifications included in this section because this is the only established industry standard. The depth setting description and calculation is the only proposed requirement that would impose a new cost beyond the baseline. The required calculations would be submitted for every well that is worked over where tubing is pulled and then reinstalled.

The proposed requirement to include additional information in the APM would result in a labor cost to industry and BSEE. To calculate the industry labor cost associated with this new requirement, we multiplied the time required to add the new descriptions and calculations to an APM by the average hourly compensation rate of the industry staff most likely to complete this task and by the number of wells with pulled and reinstalled packers for which an APM would be submitted per year. To calculate the new annual labor cost to BSEE, we multiplied the time that BSEE would spend to review the new information in an APM by the average hourly compensation rate of the BSEE staff most likely to complete this task and by the number of wells with pulled and reinstalled packers for which an APM would be submitted per year. These calculations resulted in average annual labor costs for this proposed documentation requirement of $22,316 to industry and $17,719 to BSEE.[13]

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[13] We assumed that industry staff (a mid-level engineer) would spend 0.25 hours to include the additional information in the APM for a well. We also assumed that APMs would be submitted for an average of 1,010 wells with pulled and reinstalled packers per year. We multiplied the number of industry staff hours per well by the average hourly compensation rate for a mid-level industry engineer ($88.38) and the estimated number of wells with pulled and reinstalled packers for which an APM would be submitted per year to obtain an average annual labor cost to industry of $22,316 (0.25 x $88.38 x 1,010). We assumed that BSEE staff (a mid-level engineer) would spend 0.25 hours to review the additional information in the APM for a well. We multiplied the number of BSEE staff hours per well by the average hourly compensation rate for a mid-level BSEE engineer ($70.17) and by the estimated number of wells with pulled and reinstalled packers for which an APM would be submitted per year to obtain an average annual labor cost to BSEE of $17,719 (0.25 x $70.17 x 1,010).

g. Rig movement reporting

Section 250.712 would list requirements for reporting movement of rig units to the BSEE District Manager. Revised paragraph (a) would extend the rig movement reporting requirements to all rig units conducting operations covered under this subpart, including MODUs, platform rigs, snubbing units, lift boats, and coiled tubing units. Proposed paragraphs (c) and (e) are new and would require notification if a MODU or platform rig is to be warm or cold stacked and when a drilling rig enters OCS waters. Paragraph (f) would be revised to clarify that, if the anticipated date for initially moving on or off location changes by more than 24 hours, an updated Movement Notification Report would be required. Currently, movement reports are only required for drilling operations, but the proposed rule would require operators to submit movement reports for other operations as well, including when rigs are stacked or enter OCS waters. These changes would allow BSEE to better anticipate upcoming operations, locate MODUs and platform rigs in case of emergency, and verify rig fitness.

The proposed requirement to notify BSEE of rig unit movement would result in a labor cost to industry and BSEE. To calculate the industry labor cost, we multiplied the time required to submit a report by the average hourly compensation rate of the industry staff most likely to complete this task and by the number of additional reports expected per year. To calculate the new annual labor cost to BSEE, we multiplied the time that BSEE would spend to process each report by the average hourly compensation rate of the BSEE staff most likely to complete this task and by the number of additional reports expected per year. These calculations result in average annual labor costs for this proposed reporting requirement of $2,485 to industry and $3,156 to BSEE.[14]

[14] We assumed that industry staff (administrative) would spend five minutes (0.08 hours) to submit a movement report and that industry would submit an average of 1,000 movement reports per year as a result of the new requirement. We multiplied the number of industry staff hours per report by the average hourly compensation rate for an administrative staff ($29.82) and the average number of reports per year to obtain an average annual

h. Fitness requirements for MODUs and lift boats

Proposed section 250.713(a) would add a requirement that operators provide fitness information for a MODU or lift boat for workovers, completions, and decommissioning. Operators must provide information and data to demonstrate the drilling unit's capability to perform at the proposed drilling location. This information must include the most extreme environmental and operational conditions that the unit is designed to withstand, including the minimum air gap necessary for both hurricane and non-hurricane seasons. If sufficient environmental information and data are not available at the time the APD or APM is submitted, the District Manager may approve the APD or APM but require operators to collect and report this information during operations. Under this circumstance, the District Manager continues to have the right to revoke the approval of the APD or APM if information collected during operations show that the drilling unit is not capable of performing at the proposed location.

This proposed requirement would result in labor costs to industry and BSEE. To calculate the industry labor cost, we multiplied the time required to record and submit the report by the average hourly compensation rate of the industry staff most likely to complete this task and by the number of APMs per year. To calculate the BSEE labor cost, we multiplied the time that BSEE would spend to review the information by the average hourly compensation rate of the BSEE staff most likely to complete this task and by the number of APMs per year. These calculations resulted in average annual labor costs for this proposed reporting requirement of $44,190 to industry and $35,086 to BSEE.[15]

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labor cost to industry of $2,485 (0.0833 x $29.82 x 1,000). We assumed that BSEE staff (clerical) would spend five minutes (0.08 hours) to process a movement report. We multiplied the number of BSEE staff hours per report by the average hourly compensation rate for a clerical staff ($37.87) and by the average number of reports per year to obtain an average annual labor cost to BSEE of $3,156 (0.0833 x $37.87 x 1,000).

[15] We assumed that industry staff (a mid-level engineer) would spend 0.5 hours per APM to provide the additional information and that an average of 1,000 APMs would be affected per year. We multiplied the number of industry staff hours per APM by the average hourly compensation rate for a mid-level industry engineer ($88.38) and by the estimated number of APMs affected per year to obtain an average annual labor cost to industry of $44,190 (0.5 x

i. Foundation requirements for MODUs and lift boats

Proposed section 250.713(b) would introduce a requirement for foundation requirements for workovers, completions, and decommissioning. Operators must provide information to show that site-specific soil and oceanographic conditions are capable of supporting the proposed rig unit. If operators provide sufficient site-specific information in the Exploration Plan (EP), Development and Production Plan (DPP), or Development Operations Coordination Document (DOCD) submitted to the Bureau of Ocean Energy Management (BOEM), operators may reference that information. Current regulations state that the District Manager may require operators to conduct additional surveys and soil borings before approving the APD, if additional information is needed to make a determination that the conditions are capable of supporting the rig unit or equipment installed on a subsea wellhead. For moored rigs, operators must submit a plan of the rigs' anchor patterns approved in the EP, DPP, or DOCD in the APD or APM.

This proposed requirement would result in labor costs to industry and BSEE. To calculate the industry labor cost, we multiplied the time required to record and report information by the average hourly compensation rate of the industry staff most likely to complete this task and by the number of APMs per year. To calculate the BSEE labor cost, we multiplied the time that BSEE would spend to review the information by the average hourly compensation rate of the BSEE staff most likely to complete this task and by the number of APMs per year. These calculations resulted in average annual labor costs for this proposed reporting requirement of $44,190 to industry and $35,086 to BSEE.[16]

$88.38 x 1,000). We assumed that BSEE staff (a mid-level engineer) would spend 0.5 hours to review the information. We multiplied the number of BSEE staff hours per APM by the average hourly average hourly compensation rate for a mid-level BSEE engineer ($70.17) and by the average number of APMs affected per year to obtain an average annual labor cost to BSEE of $35,086 (0.5 x $70.17 x 1,000).

[16] We assumed that industry staff (a mid-level engineer) would spend 0.5 hours per APM to provide the additional information and that an average of 1,000 APMs would be affected per year. We multiplied the number of industry

j. Real-time monitoring of well operations

Proposed section 250.724 is a new section that would list requirements for:

(1) Monitoring well operations on rigs that have a subsea BOP, floating facilities using surface BOPs, and rigs operating in high pressure and high temperature (HPHT) reservoirs, and

(2) Storing data at a designated onshore location, as listed in the APD or APM.

In order to comply with this section, industry would incur annual equipment and labor costs associated with gathering, recording, transmitting, and storing data. To calculate the costs associated with these new requirements, we estimated the average equipment and labor cost per day to perform continuous monitoring (based on BSEE's interactions with the industry and review of the equipment involved), and the average amount of time that a rig would engage in well operations per year (and would thus be subject to this monitoring requirement). We assumed that this type of service mostly lends itself to a day rate, and multiplied the cost per day to perform the monitoring by the number of days per year that the rig would be engaged in well operations. We then multiplied the product by the number of rigs that would incur this new cost. This calculation resulted in average annual equipment and labor costs for this monitoring requirement of $40.5 million to industry.[17] No additional costs to BSEE are expected as a result of this requirement. BSEE requests information related to the cost associated with these proposed real-time monitoring requirements.

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staff hours per APM by the average hourly compensation rate for a mid-level industry engineer ($88.38) and by the estimated number of APMs affected per year to obtain an average annual labor cost to industry of $44,190 (0.5 x $88.38 x 1,000). We assumed that BSEE staff (a mid-level engineer) would spend 0.5 hours to review the information. We multiplied the number of BSEE staff hours per APM by the average hourly average hourly compensation rate for a mid-level BSEE engineer ($70.17) and by the average number of APMs affected per year to obtain an average annual labor cost to BSEE of $35,086 (0.5 x $70.17 x 1,000).

[17] We assumed that the average costs per day and the average operational days per year would be the same for rigs with subsea BOPs and rigs operating in HPHT reservoirs. We assumed that a rig operates for 270 days per year (three operations per year and three months per operation) and that the average cost per day to perform continuous monitoring would be $5,000, including equipment and labor. BSEE regulatory staff, in conjunction with

k. <u>Additional documentation and verification requirements for BOP systems and system components</u>

Section 250.730 would list general requirements for BOP systems and system components and add new documentation and verification requirements. Proposed section 250.730(d) would require that quality management systems for the manufacture of BOP stacks be certified by an entity that meets the requirements of International Organization for Standardization (ISO) 17011. Additionally, operators may submit a request for approval of equipment manufactured under quality assurance programs other than API Specification Q1, and BSEE may approve such a request provided the operator would submit relevant information about the alternative program. In regard to new paragraph (d), we were unable to determine the additional cost associated with the required certification by an entity that meets the requirements of ISO 17011 for quality management. BSEE requests feedback from the public or industry on estimates for this cost. Additionally, new paragraph (d) would result in labor costs to industry associated with submitting requests for alternative programs.

We multiplied the hourly compensation rate for the industry staff most likely to complete this work by the amount of time expected to submit the request and then multiplied this annual cost by the total number of wells that would incur costs. These calculations resulted in an annual cost to industry of $1,768 associated with these submissions. This new requirement would also result in labor costs to BSEE associated with processing these requests. We multiplied the hourly compensation rate for the BSEE staff most likely to complete this work by the amount of time expected to process the request and

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BSEE engineers who interact with industry on a regular basis and review the equipment, estimated this cost. BSEE requests comments on the reasonableness of this estimate. We also estimated that half of the rigs with subsea BOPs already conduct this monitoring. Thus, only half of rigs with subsea BOPs (20 rigs) would incur a new cost to comply with these requirements. Similarly, we assumed that 10 of the rigs operating in HPHT reservoirs would incur a new cost to comply with these requirements. We multiplied the time that the rig is operational per year by the average cost per day to perform monitoring and by the number of affected rigs to obtain an average annual equipment and labor cost to industry of $40,500,000 (270 x $5,000 x 30).

then multiplied this annual cost by the total number of wells that would incur costs. These calculations resulted in an annual cost to BSEE of $702 associated with these submissions.[18] BSEE was unable to estimate the cost for the requirement that a certification entity meet the requirements of ISO 17011 for quality management systems for BOP stacks. BSEE requests feedback related to the costs associated with these proposed requirements for BOP systems and system components.

Proposed section 250.731(c) would require verification by a BSEE-approved verification organization of specified aspects of equipment design, equipment tests, shear tests, and pressure integrity tests; all certification documentation must be made available to BSEE. The requirements laid out in section 250.731(c) regarding certification for BOP systems and systems components would result in new equipment and service costs to industry. We estimated a one-time cost to industry for equipment and service and multiplied the cost by the number of wells that would incur this new cost. This calculation resulted in one-time equipment and service costs for this proposed certification requirement of $12.8 million to industry.[19]

Proposed section 250.732(c) would require a comprehensive review by a BSEE-approved verification organization of BOP and related equipment being proposed for use in high temperature and high pressure service. The requirements in new section 250.732(c) surrounding a review of BOP systems and systems components in HPHT conditions would result in new annual costs to industry. To calculate the

[18] We assumed that a mid-level industry engineer would spend 2 hours to submit a request. We multiplied the compensation rate for a mid-level industry engineer ($88.38) by the number of hours to complete the submission and then multiplied this annual cost by the total number of wells (10) to determine the annual cost to industry of $1,768 (2 × $88.38 × 10). We assumed that a mid-level BSEE engineer would spend 1 hour to process a request. We multiplied the compensation rate for a mid-level BSEE engineer ($70.17) by the number of hours to complete the task and then multiplied this cost by the total number of wells (10) to determine the annual cost to industry of $702 (1 × $70.17 × 10).

[19] We assumed that the equipment and service costs per well would be $40,000. We estimated that 320 wells would incur a new cost to comply with these requirements. We multiplied the one-time cost of equipment and service by the number of affected wells to obtain one-time equipment and service costs to industry of $12,800,000 ($40,000 x 320).

costs associated with the required verifications of BOP system and components by BSEE-approved verification organizations, we estimated the annual cost for performing the verification and multiplied the annual cost by the number of wells that would incur this new cost. This calculation resulted in annual equipment and labor costs for this proposed verification requirement of $500,000 to industry.[20]

l. Additional information in the APD, APM, or other submittal for BOP systems and system components

Section 250.731 lists the descriptions of BOP systems and system components that must be included in the applicable APD, APM, or other submittal for a well. Revised paragraph (a) would require the submittal to include descriptions of the rated capacities for the fluid-gas separator system, control fluid volumes, control system pressure to achieve a seal of each ram BOP, number of accumulator bottles and bottle banks, and control fluid volume calculations for the accumulator system.

New paragraph (e) would require a listing of the functions with sequences and timing of autoshear, deadman, and EDS for subsea BOPs. Paragraph (b) would add schematic drawing requirements, including labeling for the control system alarms and set points, control stations, and riser cross section. For subsea BOPs, surface BOPs on floating facilities, and BOPs operating under HPHT conditions, new paragraph (f) would require submission of a certification that a Mechanical Integrity Assessment report has been submitted within the past 12 months. New paragraphs (c) and (d) would include a change in required certifications; the paragraphs would require submission of certification from a BSEE-approved verification organization (rather than a “qualified third party”) that:

(1) Test data demonstrate that the shear ram(s) will shear the drill pipe at the water depth, and

[20] We assumed that the annual costs would be $50,000, including equipment and service. We estimated that 10 wells would incur a new cost to comply with these requirements. We multiplied the annual cost of equipment and service by the number of affected wells to obtain an average annual equipment and service cost to industry of $500,000 ($50,000 x 10).

(2) The BOP has been designed, tested, and maintained to perform at the most extreme anticipated conditions, and

(3) That the accumulator systems have sufficient fluid to function the BOP system without assistance from the charging system.

These proposed requirements are necessary to enhance BSEE's review of the BOP system and its emergency systems, which were the topic of many of the recommendations of the *Deepwater Horizon* incident investigation teams. Additionally, these requirements are necessary to help BSEE verify that the accumulator system would have sufficient fluid to function the BOP system without assistance from the charging system.

The proposed requirements to provide additional documentation about the BOP system and system components in the APD, APM, or other submittal would result in labor costs to industry and BSEE. To calculate the industry labor cost associated with these new requirements, we multiplied the estimated time it would take to document the required information in an APD, APM, or other submittal by the average hourly compensation rate of the industry staff most likely to complete this task. We then multiplied the product by the estimated number of wells drilled per year.

Likewise, to calculate the new annual labor cost to BSEE, we multiplied the time that BSEE would spend to process each submittal by the average hourly compensation rate of the BSEE staff most likely to complete this task and by the estimated number of wells drilled per year. These calculations resulted in average annual labor costs for this documentation requirement of $28,282 to industry and $22,455 to BSEE.[21] BSEE was unable to locate any applicable data or comparative cost estimates and therefore was

[21] We assumed that industry staff (a mid-level engineer) would spend one hour to include additional information in the APD, APM, or other submittal for a well. We multiplied the number of industry staff hours per well by the average hourly compensation rate for a mid-level industry engineer ($88.38) and by the average number of wells

unable to determine a definitive cost estimate for the annual costs to industry associated with the change in requiring use of BSEE-approved verification organizations referenced in new paragraph 250.732(a). BSEE requests information concerning costs associated with the proposed use of BSEE-approved verification organizations.

m. Submission of a Mechanical Integrity Assessment Report

Proposed section 250.732(d) would include new requirements on the submission of a Mechanical Integrity Assessment Report on certain BOP stack and systems. New paragraph (d) would outline the requirements for this report, which must be completed by a BSEE-approved verification organization and submitted by the operator for operations that would require the use of a subsea BOP, a surface BOP on a floating facility, or a BOP that is being used in HPHT operations. New section 250.731(f) would require certification stating that this report be submitted to BSEE prior to beginning any operations (to include maintenance and repairs) involving these BOPs. The third-party reporting would enhance the BSEE review and permitting process and ensure that BSEE is aware of repairs or other changes to the operating BOPs.

These reporting requirements would result in new capital costs to industry and new labor costs to industry and BSEE associated with the submission and review of reports. To calculate the capital costs to industry of submitting Mechanical Integrity Assessment reports, we multiplied the annual capital cost of submitting the report by the estimated number of wells that would be affected. This calculation resulted in annual capital costs for reporting of $4.8 million to industry. To calculate the industry labor

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drilled per year (320) to obtain an average annual labor cost to industry of $28,282 (1 x $88.38 x 320). We assumed that BSEE staff (a mid-level engineer) would spend one hour to review the additional information in the APD, APM, or other submittal for a well. We multiplied the number of BSEE staff hours per submittal by the average hourly compensation rate for a mid-level BSEE engineer ($70.17) and by the average number of wells drilled per year to obtain an average annual labor cost to BSEE of $22,455 (1 x $70.17 x 320).

cost, we multiplied the time required to submit a report by the average hourly compensation rate of the industry staff most likely to complete this task and then multiplied this annual cost by the number of additional reports expected per year.

To calculate the new annual labor cost to BSEE, we multiplied the time that BSEE would spend to process each report by the average hourly compensation rate of the BSEE staff most likely to complete this task and then multiplied this annual cost by the number of additional reports expected per year. These calculations result in average annual labor costs for this reporting requirement of $14,141 to industry and $11,228 to BSEE. We then summed the labor and reporting costs to industry to obtain an annual cost to industry of $4.8 million and annual costs to BSEE of $11,228.[22]

n. New surface BOP requirements

Section 250.733 would include new requirements for surface BOP stacks. Proposed new paragraph (e) would require that hydraulically operated locks are installed with surface BOPs.

BSEE recognizes that the equipment and labor costs associated with the proposed surface BOP stack requirements would be case-specific. BSEE was unable to locate any applicable data or comparative cost estimates and therefore was unable to determine a definitive cost estimate for the labor and equipment costs to industry associated with the installation of hydraulically operated locks. BSEE

[22] For capital costs, we assumed an annual cost of $15,000 for each well which results in an annual capital cost of $4.8 million ($15,000 x 320). For labor costs, we assumed that industry staff (a mid-level engineer) would spend a half hour to prepare a report for each well. We multiplied the number of industry staff hours per well by the average hourly compensation rate for a mid-level industry engineer ($88.38) and by the average number of wells drilled per year (320) to obtain an average annual labor cost to industry of $14,141 (0.5 x $88.38 x 320). We assumed that BSEE staff (a mid-level engineer) would spend a half hour to receive and review the report for each well. We multiplied the number of BSEE staff hours per submittal by the average hourly compensation rate for a mid-level BSEE engineer ($70.17) and by the average number of wells drilled per year to obtain an average annual labor cost to BSEE of $11,228 (0.5 x $70.17 x 320).

requests information concerning costs associated with these proposed new requirements for BOP stacks. [23]

o. New subsea BOP system requirements

Section 250.734 would include new requirements for subsea BOP systems, based on recommendations from the *Deepwater Horizon* incident investigations. Revised paragraph (a) would require that BOPs be equipped with two shear rams and outlines the requirements for the shear rams. BSEE is also considering requiring installation of technology that is capable of severing any components of the drill string (excluding drill bits) within 10 years of the publication date of the rule.

BSEE recognizes that the equipment costs associated with these new subsea BOP system requirements would be case-specific. For example, the costs would depend on the age of the rig and BOP system, the BOP system type, and the size of the rig, among other factors. In order to estimate the cost to industry associated with these new shear ram requirements, we multiplied the estimated cost of compliance per rig by the estimated number of affected rigs. API Standard 53 includes the requirements under paragraph (a) for all rigs with the exception of moored rigs. We multiplied the cost of compliance for a moored rig by the number of moored rigs in order to calculate the one-time equipment costs of \$50 million for this requirement.[24] BSEE requests comments concerning the costs of compliance with these new requirements.

[23] BSEE subject matter experts estimate this cost to be nominal and would not significantly alter the estimate. It is BSEE's understanding that this type of equipment usually comes standard on new orders and the costs associated within this equipment are a part of the entire component and not a separate cost.

[24] We estimated that 5 moored rigs would be affected and that the one-time capital compliance costs associated with these shear ram requirements would be \$10,000,000 per rig. To calculate the total one-time capital costs to industry, we multiplied the equipment cost per rig by the number of affected rigs to yield a total cost to industry of \$50,000,000 (\$10,000,000 x 5).

p. New surface accumulator system requirements

Section 250.735(a) would list new requirements for the surface accumulator system of a BOP. The surface accumulator system must operate all BOP functions against MASP with at least 200 pounds per square inch remaining on the bottles above the precharge pressure without use of the charging system. Revised paragraph (a) would detail additional surface accumulator requirements regarding fluid capacity and accumulator regulators. This revision would ensure that the BOP system is capable of operating all critical functions.

The requirement that the surface accumulator system operate all functions for all BOP systems would result in a one-time equipment and labor cost to industry. The equipment cost would result from the installation of additional equipment necessary to meet the requirement. To calculate the equipment cost, we multiplied the average cost for equipment per rig by the total number of rigs. For the labor cost, we multiplied the time required per rig to install the equipment by the average hourly compensation rate of the industry staff most likely to do the work and by the total number of rigs. This calculation resulted in a one-time cost to industry of $2.8 million.[25] No additional costs to BSEE are expected as a result of this proposed requirement.

q. Chart recorders

[25] We assumed that the average cost of the additional equipment needed to meet the requirements would be $25,000 per rig. It is unknown how many rigs already comply; thus, we made a assumption that all rigs would be affected (90 rigs). We multiplied the equipment cost per rig by the number of affected rigs to obtain an estimated one-time equipment cost of $2.25 million ($25,000 x 90). For the one-time labor cost to industry, it was estimated that one to three days of industry time would be required per rig to install the new equipment. We assumed that industry staff (a mid-level engineer) would spend 72 hours to install the new equipment on a rig. We multiplied the number of industry staff hours per rig by the average hourly compensation rate for a mid-level industry engineer ($88.38) and by the number of affected rigs to obtain an estimated one-time labor cost to industry of $572,702 (72 x $88.38 x 90). Summing the equipment and labor costs resulted in a total one-time cost to industry of $2,822,708 for this requirement.

Section 250.737(c), which addresses BOP testing requirements, would introduce a requirement that each test must hold the required pressure for five minutes while using a four-hour chart. This chart would contain sufficient detail to show if a leak occurred during the test.

This proposed testing requirement would result in a one-time equipment and labor cost to industry. Industry would have to purchase the equipment (a chart recorder) to be able to comply with the testing requirement. To calculate the equipment cost, we multiplied the estimated cost of equipment per rig by the total number of rigs. To calculate the one-time labor cost to industry, we multiplied the time required per rig to install the chart recorder by the average hourly compensation rate of the industry staff most likely to complete this task and by the total number of rigs. This calculation resulted in a one-time cost to industry of $180,426.[26] No additional costs to BSEE are expected as a result of this proposed requirement.

r. <u>Notification and procedures requirements for testing of surface BOP systems</u>

Proposed section 250.737(d)(2) would expand notification and procedures requirements regarding the use of water to test a surface BOP system. These expanded notification and procedures requirements would result in increased labor costs to industry. To calculate the new annual labor cost to industry, we multiplied the hourly compensation rate for the industry staff most likely to complete this work by the amount of time expected to complete the submittals and then multiplied this annual cost by the total number of submittals. These calculations resulted in an annual cost to industry of $5,303 associated with these submissions. This new requirement would also result in labor costs to

[26] We assumed that each rig would require a chart recorder for an average cost of $2,000 per rig. We multiplied the average equipment cost per rig by the total number of rigs (90) to obtain an estimated one-time equipment cost to industry of $180,000 ($2,000 x 90). We assumed that industry staff (rig crew) would spend five minutes (0.08 hours) per rig to install the equipment. We multiplied the number of industry staff hours per rig by the average hourly compensation rate for a rig crew staff ($56.80) and by the total number of rigs to obtain an estimated one-time labor cost to industry of $426 (0.0833 x $56.80 x 90). Summing the equipment and labor costs resulted in a total one-time cost to industry of $180,426.

BSEE associated with processing these requests. We multiplied the hourly compensation rate for the BSEE staff most likely to complete this work by the amount of time expected to process the submittals and then multiplied this annual cost by the total number of submittals.[27] These calculations resulted in an annual cost to BSEE of $4,210 associated with these submissions. BSEE requests information related to the costs associated with this proposed expansion of notification and procedures requirements.

s. Alternating BOP control station function testing

Section 250.737(d)(5) would expand the requirements for function testing of BOP control stations. It would require that the operator designate the BOP control stations as primary and secondary and function test of each station weekly.

This proposed testing requirement would result in increased operating costs to industry. To calculate the annual operations costs associated with this requirement, we multiplied the time required to conduct the testing per rig by the daily rig operating cost and by the estimated number of rigs affected per year. Because subsea and surface BOPs have different daily rig operating costs, we performed separate calculations for the costs for subsea and surface BOP rigs. We estimated an increased annual operating cost to industry associated with this provision of $25 million.[28] BSEE

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[27] We assumed that a mid-level industry engineer would spend 1 hour on a submittal as a result of these expanded requirements. We multiplied the compensation rate for a mid-level industry engineer ($88.38) by the number of hours to complete the submission and then multiplied this annual cost by the total number of submittals (60) to determine the annual cost to industry of $5,303 (1 × $88.38 × 60). We assumed that a mid-level BSEE engineer would spend 1 hour to process a submittal. We multiplied the compensation rate for a mid-level BSEE engineer ($70.17) by the number of hours to complete the task and then multiplied this cost by the total number of submittals (60) to determine the annual cost to industry of $4,210 (1 × $70.17 × 60).

[28] We assumed that testing would require 0.5 days per rig per year (one hour every week for three months). Because subsea and surface BOPs rigs have different daily rig operating costs, we performed separate calculations for the costs for subsea and surface BOP rigs. For subsea BOP rigs, we multiplied the time required to conduct the testing per rig by the daily rig operating cost for subsea BOP rigs ($1 million) and by the number of subsea BOP rigs (40) for an annual cost of $20 million for subsea BOP rigs (0.5 x $1 million x 40). For surface BOP rigs, we multiplied the time required to conduct the testing per rig by the daily rig operating cost for surface BOP rigs ($200,000) and by the number of surface BOP rigs (50) for an annual cost of $5 million for surface BOP rigs (0.5 x $200,000 x 50).

requests information related to the costs associated with the proposed expansion of the testing criteria for BOP control station function testing.

t. ROV intervention function testing

Proposed section 250.737(d)(12) would include requirements for testing ROV intervention functions to include testing and verifying the closure of all ROV intervention functions. The operator would have to test and verify closure of the selected ram.

This testing requirement would result in increased annual operating costs to industry. To calculate the annual operating costs, we multiplied the time required to conduct the testing per subsea BOP rig by the daily operating cost for a subsea BOP rig and by the estimated number of subsea BOP rigs affected per year. We estimated the annual increased operating cost to industry for this requirement to be $416,667.[29] No additional costs to BSEE are expected as a result of this proposed requirement.

u. Autoshear, deadman, and EDS system function testing on subsea BOPs

Proposed section 250.737(d)(13) would expand the requirements for function testing of autoshear, deadman, and EDSs on subsea BOPs. It would require the test procedures submitted for the BSEE District Manager's approval to include schematics of the actual controls and circuitry of the system, the approved schematics of the BOP control system, and a description of how the ROV would be used during the operation. It also outlines the requirements for the deadman system test, including a requirement that the testing must indicate the discharge pressure of the subsea accumulator system

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Summing the annual costs for subsea BOP rigs and surface BOP rigs resulted in a total annual increased operating cost to industry associated with this provision of $25 million.

[29] We assumed that it would take five minutes per well to conduct the testing and that each subsea BOP rig has three wells, yielding a total time requirement of 15 minutes (0.0104 days) per rig. We multiplied the time diverted for testing per rig by the daily operating cost per subsea BOP rig ($1,000,000) and by the estimated number of subsea BOP affected per year (40) to obtain an annual increased operating cost to industry of $416,667 (0.0104 x40 x $1,000,000).

throughout the test. It would require that the blind-shear rams be tested to verify closure. The operator must document the plan to verify closure of the casing shear ram, if installed, as well as all test results.

These proposed documentation and testing requirements would result in a one-time equipment cost and increased annual operating costs to industry. The OCS industry would incur a one-time equipment cost to purchase a sensing device to detect the discharge pressure during deadman system testing. We multiplied the average cost per rig of the sensing device by the estimated number of subsea BOP rigs required to comply. We assumed installation costs to be negligible because the sensing device would be installed as part of routine servicing. In order to calculate the annual operations cost, we multiplied the estimated time per subsea BOP rig required to comply with the document and testing requirements by the daily operating cost for a subsea BOP rig and by the estimated number of subsea BOP rigs affected per year. These calculations resulted in a one-time equipment cost to industry of $100,000 and an average annual increased operating cost to industry of $5 million.[30] No additional costs to BSEE are expected as a result of this proposed requirement.

v. Approval for well control equipment not covered in Subpart G

Proposed section 250.738 would describe the required actions for specified situations involving BOP equipment or systems. Paragraphs (b), (i), and (o) would include requirements for reports from verification organizations. Reports previously required to be prepared by a "qualified third party" under

[30] We assumed that the average cost of the sensing device would be $2,500 per rig. We multiplied the equipment cost by the total number of subsea BOP rigs (40) to obtain the one-time equipment cost to industry of $100,000 ($2,500 x 40). We assumed that it would take one hour per well to perform the testing and documentation tasks required by this provision per well and that each subsea BOP rig has three wells, for a total time requirement per subsea BOP of three hours (0.125 days). We also assumed that all subsea BOP rigs (40) would be affected. We multiplied the time diverted for testing by the daily operating cost per subsea BOP rig ($1,000,000) and by the estimated number of subsea BOP rigs affected per year to obtain an average annual increased operating cost to industry of $5 million (0.125 x $1,000,000 x 40).

these sections would be required to be prepared by a "BSEE-approved verification organization." Paragraph (m) would include a similar change and introduce a requirement that an operator request approval from the BSEE District Manager to use well control equipment not covered in Subpart G. The operator must submit a report from a BSEE-approved verification organization, as well as any other information required by the District Manager.

This proposed approval request requirement would result in labor costs to industry and BSEE. In order to calculate the annual labor costs for industry, we multiplied the estimated time required to submit an approval request and BSEE-approved verification organization report by the average hourly compensation rate of the industry staff most likely to complete this task and by the estimated number of rigs that would require approval for well control equipment per year. For BSEE, we multiplied the estimated time to review the submissions by the average hourly compensation rate of the BSEE staff most likely to complete this task, and the estimated number of rigs for which an approval request and report would be submitted per year. These calculations resulted in average annual labor costs of $88 to industry and $70 to BSEE.[31] BSEE was unable to locate any applicable data or comparative cost estimates and therefore was unable to determine a definitive cost estimate for the annual costs to industry associated with the third-party verification. BSEE requests information concerning costs associated with the proposed third-party verification requirements.

[31] We assumed that industry staff (a mid-level engineer) would spend 0.5 hours to submit an equipment approval request and report. We also assumed that industry would submit a request and report for an average of two deepwater rigs per year. We multiplied the number of industry staff hours per submission by the average hourly compensation rate for a mid-level industry engineer ($88.38) and the average number of submissions per year to obtain an average annual labor cost to industry of $88 (0.5 x $88.38 x 2). We assumed that BSEE staff (a mid-level engineer) would spend 0.5 hours to review a submission. We multiplied the number of BSEE staff hours per submission by the average hourly compensation rate for a mid-level BSEE engineer ($70.17) and by the estimated number of submissions per year to obtain an average annual labor cost to BSEE of $70 (0.5 x $70.17 x 2).

w. Breakdown and inspection of BOP system and components

Proposed section 250.739(b) would introduce a requirement for a complete breakdown and inspection of the BOP and every associated component every 5 years. During this complete breakdown and inspection, a BSEE-approved verification organization must document the inspection and any problems encountered. This BSEE-approved verification organization report must be available to BSEE upon request. This additional requirement is necessary to ensure that the components on the BOP stack would be regularly inspected. In the past, BSEE has, in some cases, seen components of BOP stacks go more than 10 years without this type of inspection.

This proposed inspection and documentation requirement would result in cost to industry associated with generating reports by BSEE-approved verification organizations. To calculate this report cost, we multiplied the estimated report cost per rig provided by subject matter experts by the number of reports completed per rig annually and by the estimated number of rigs in operation per year. Because subsea and surface BOPs differ in structure, they incur different costs to break down and inspect. In order to reflect these differences, we performed separate calculations for the costs for subsea and surface BOP rigs. We assumed that costs would be incurred in year 1 and year 6 of the 10-year analysis period. These calculations resulted in a total cost to industry to obtain third-party reports of $21.5 million[32] during the year of inspection, which would occur once every 5 years or twice during the 10-year analysis period, for a total of $43 million.

[32] For subsea BOP rigs, based on input from subject matter experts, we assumed that equipment and labor cost would be $350,000 per rig. We multiplied the total number of subsea BOP rigs (40) by the equipment and labor cost to obtain an inspection-year cost of $14 million (40 x $350,000) which occurs every five years for subsea BOP rigs. For surface BOP rigs, based on input from subject matter experts, we assumed that equipment and labor cost would be $150,000 per rig. We multiplied the total number of surface BOP rigs (50) by the equipment and labor cost to obtain an inspection-year cost of $7.5 million (50 x $150,000) which occurs every five years, for surface BOP rigs.

x. <u>Additional recordkeeping for real-time monitoring</u>

Proposed sections 250.740(a) and § 250.741(b) would introduce requirements for recordkeeping of real-time monitoring data and other for well operation data. These additional records would require labor costs to industry. To calculate the annual labor costs for industry, we multiplied the estimated time required to keep real-time monitoring records per well by the average hourly compensation rate of the industry staff most likely to complete this task and by the estimated number of wells affected per year. These calculations resulted in average annual labor costs of $1,789 to industry.[33] No additional costs to BSEE are expected as a result of these requirements.

y. <u>Industry familiarization with the new rule</u>

When the new regulation takes effect, operators would need to read and interpret the rule. Through this review, operators would familiarize themselves with the structure of the new rule and identify any new provisions relevant to their operations. Operators would evaluate whether any new action must be taken to achieve compliance with the rule.

Reviewing the new regulations would require staff time, imposing a one-time labor cost on industry. We estimated the one-time labor cost by multiplying the time required for an administrator at each field office to review the rule by the total number of field offices. This calculation resulted in a total one-time cost to industry of $28,059.[34]

[33] We assumed that industry staff (administrative staff) would spend 0.5 hours to keep real time monitoring records per well. We multiplied the number of industry staff hours per well by the average hourly compensation rate for administrative staff ($29.82) and then multiplied this cost by the number of affected wells (120, based on an assumption of three wells per subsea BOP rig) to obtain an average annual labor cost of $1,789 (0.5 x $29.82 x 120).

[34] We assumed that industry staff (a professional engineer, supervisory) would spend two hours to review the new regulation. The average hourly wage rate for a professional engineer (supervisory) is $76.00, based on BSEE's Supporting Statement A (BSEE Production Safety Systems). We multiplied this wage rate by the private sector loaded wage factor of 1.42 to account for employee benefits, resulting in a loaded average hourly compensation

6. Summary of the cost analysis

Exhibit 1 summarizes the estimated cost for the proposed rule by provision. Exhibit 2 displays the monetized costs as annual summations of the calculations described above and as a 10-year total. The increase in the annual cost estimate for the year 2019 reflects the inspection-year costs that would occur every 5 years, as described in section 5.w above. Sums in Exhibit 1 and those that follow may not add because of rounding.

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rate of $107.92. We assumed that an industry staff would review the new regulation at each of the 130 field offices. Multiplying the number of hours per review by the average hourly compensation rate and by the number of field offices resulted in an estimated one-time labor cost of $28,059 (2 x $107.92 x 130) to industry.

EXHIBIT 1: COST OF THE PROPOSED RULE BY PROVISION[1]					
	Total 10 Year Cost (undiscounted)	**Average Annual Cost (undiscounted)**	**Percent of Total Cost**	**Industry Share**	**Government Share**
(a) Additional information in the description of well drilling design criteria	$282,819	$28,282	0.03%	100%	0%
(b) Additional information in the drilling prognosis	$70,705	$7,070	0.01%	100%	0%
(c) Prohibition of a liner as conductor casing	$7,950,000	$795,000	0.90%	100%	0%
(d) Additional capping stack testing requirements	$800,000	$80,000	0.09%	100%	0%
(e) Additional information in the APM for installed packers	$103,060	$10,306	0.01%	56%	44%
(f) Additional information in the APM for pulled and reinstalled packers	$400,347	$40,035	0.05%	56%	44%
(g) Rig movement reporting	$56,411	$5,641	0.01%	44%	56%
(h) and (i) Information on MODUs, including lift boats	$1,585,532	$158,553	0.18%	56%	44%
(j) Real-time monitoring of well operations	$405,000,000	$40,500,000	45.85%	100%	0%
(k) Additional documentation and certification requirements for BOP systems and system components	$17,824,693[2]	$1,782,469[2]	2.02%	100%	0%
(l) Additional information in the APD, APM, or other submittal for BOP systems and system components	$507,370	$50,737	0.06%	56%	44%
(m) Submission of a Mechanical Integrity Assessment Report by a BSEE approved certification body	$48,253,685	$4,825,369	5.46%	100%	0%
(n) New surface BOP requirements	Data not available; requesting comments				
(o) New subsea BOP system requirements	$50,000,000[2]	$5,000,000[2]	5.66%	100%	0%
(p) New surface accumulator system requirements	$2,822,708	$282,271	0.32%	100%	0%
(q) Chart recorders	$180,426	$18,043	0.02%	100%	0%
(r) Use water to test surface BOP system	$95,132	$9,513	0.01%	56%	44%
(s) Alternating BOP control station function testing	$250,000,000	$25,000,000	28.30%	100%	0%
(t) ROV intervention function testing	$4,166,667	$416,667	0.47%	100%	0%
(u) Autoshear, deadman, and EDS system function testing on subsea BOPs	$50,100,000	$5,010,000	5.67%	100%	0%
(v) Approval for well control equipment not covered in Subpart G	$1,586	$159	0.00%	100%	0%
(w) Breakdown and inspection of BOP system and components	$43,000,000	$4,300,000	4.87%	100%	0%

Exhibit 1: Cost of the Proposed Rule by Provision[1]					
	Total 10 Year Cost (undiscounted)	**Average Annual Cost (undiscounted)**	**Percent of Total Cost**	**Industry Share**	**Government Share**
(x) Additional record-keeping for real-time monitoring	$17,892	$1,789	0.00%	100%	0%
(y) Industry familiarization with the new rule	$28,059	$2,806	0.00%	100%	0%
TOTAL	**$883,247,090**	**$88,324,709**	**100.00%**	**99.86%**	**0.14%**

[1] Totals may not add because of rounding.

[2] This is a lower-bound estimate of the costs of this provision; BSEE seeks comment on costs that we were unable to estimate (see section 5 above for details).

Exhibit 2: Summary of Monetized Costs[1]				
Year		**Industry Costs**	**Government Costs** (2012 dollars/year)	**Total Costs**
1	**2015**	$164,728,509	$134,273	$164,862,782
2	**2016**	$77,297,317	$134,273	$77,431,590
3	**2017**	$77,297,317	$134,273	$77,431,590
4	**2018**	$77,297,317	$134,273	$77,431,590
5	**2019**	$77,297,317	$134,273	$77,431,590
6	**2020**	$98,797,317	$134,273	$98,931,590
7	**2021**	$77,297,317	$134,273	$77,431,590
8	**2022**	$77,297,317	$134,273	$77,431,590
9	**2023**	$77,297,317	$134,273	$77,431,590
10	**2024**	$77,297,317	$134,273	$77,431,590
Undiscounted 10-year total		**$881,904,358**	**$1,342,732**	**$883,247,090**
10-Year Total with 3% discounting		**$762,252,353**	**$1,145,377**	**$763,397,731**
10-Year Total with 7% discounting		**$638,941,758**	**$943,078**	**$639,884,837**
10-year Average		**$88,190,436**	**$134,273**	**$88,324,709**
Annualized with 3% discounting		**$89,359,230**	**$134,273**	**$89,493,503**
Annualized with 7% discounting		**$90,970,932**	**$134,273**	**$91,105,205**

[1] Totals may not add because of rounding.

7. Benefits Analysis

We have quantified three types of benefits that would result from the proposed rule; time savings, potential reductions in oil spills, and potential reductions in fatalities (*see* Sensitivity Analysis, section 9.b, below). A time-savings benefit would result from § 250.737(d)(10), which would streamline the testing criteria for BOP control station function and reduces the time required for this testing. The section would require operators to test the functionality of the blind-shear ram.

a. Time Savings

BSEE proposes to change the testing frequency for workover and decommissioning operations to once every 14 days, which is consistent with the testing frequency for drilling and completion operations. Some drilling, completion, workover, and decommissioning operations use the same rigs and BOP systems; therefore, to ensure consistency among different operations involving the same equipment, BSEE proposes to harmonize the requirements for that type of equipment. Harmonization of the testing frequency would streamline the BOP function-testing criteria and increase safety by reducing the repetition of operations (such as pulling pipe out of the hole and running pipe back into the hole) that pose operational safety issues, thereby limiting the exposure of offshore personnel to potential risks. This may also have a positive effect on overall equipment durability and reliability. [35] The new proposed provisions within this rulemaking increase the level of safety and reduce risk which translates into the operations conducted during this time-savings benefit. When combing this provision with the rest of the proposed provisions, the rulemaking increases the level of safety and reducing the risk for these operations.

We calculated the savings from this provision by multiplying the amount of operating time saved per rig by the daily operating cost for a rig and by the number of affected rigs. Because subsea and surface BOPs have different daily rig operating costs, we calculated the time savings for subsea and surface BOP rigs separately. This calculation resulted in a total time-savings to industry of approximately $150,000,000 per year.[36]

[35]Neither Alternative 1 nor Alternative 2 consider potential benefits related to extended equipment life and reduced well control risks arising from fewer pressure tests and fewer trips out of the hole.

[36] We assumed that this requirement would save three days of operating time per rig. BSEE estimates that the pressure testing takes about 20 hours and that the trip time is about 52 hours for workover and decommissioning operations. For the 40 subsea BOP rigs, we assumed that the daily operating cost is $1,000,000, and we assumed

With regard to potential time savings for Alternative 2*,* the change in the required BOP pressure testing frequency under Alternative 2 would further change the frequency of BOP pressure testing from once every 14 days to once every 21 days and could result in a time-savings benefit to industry by decreasing the number of required tests per year for operators. To estimate the time-savings benefit associated with this potential change, we made the following assumptions:

- We assumed that operators conduct 26 tests per year (*i.e.*, one test every 14 days). BSEE recognizes that operators will not likely operate continuously, but we assumed continuous operations as a conservative approach because this approach results in the highest number of tests assumed to be conducted per year and thus the largest estimated costs per year.
- We assumed that, under this alternative, operators would conduct 17 tests per year (*i.e.*, one test every 21 days). This resulted in a net decrease of 9 tests per year (26 tests – 17 tests) under this alternative.
- We assumed that each BOP test takes 20 hours, based on input from subject matter experts contacted by BSEE.

Based on these inputs, we estimated that each rig will save 7.5 days of operating time annually (*i.e.*, 9 tests not conducted each year, with each test comprising 20 hours) as a result of Alternative 2. Using the daily rig operating costs assumed above, this would result in an annual per-rig benefit of $7.5 million for subsea BOP rigs (7.5 days x $1,000,000 per day) and $1.5 million for surface BOP rigs (7.5 days x $200,000 per day). Accounting for the number of rigs assumed to be operating on the OCS, we estimated an annual time-savings benefit of $300 million to subsea rigs ($7,500,000 x 40 rigs) and $75

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that the daily operating cost for the 50 surface BOP rigs is $200,000 per rig. We multiplied the time saved per rig by the daily operating cost per rig and by the number of affected rigs. Most rigs have the capability to perform multiple operations therefore we include all rig into this factor. This calculation resulted in an estimated annual time savings to industry of $150 million (3 x 50 x $200,000 + 3 x 40 x $1,000,000).

million for surface rigs ($1,500,000 x 50 rigs).[37] As a result, the total benefits under Alternative 2 would be approximately $525,000,000 annually (*see* Exhibit 5 for further details of these benefits).

We did not, however, include reduced trip time in the calculations of savings for Alternative 2.[38] Drilling trip time depends on factors such as well depth, hole size, mud weight, the amount of open hole, hole conditions, surge and swab pressure, borehole deviation, bottom hole assembly configuration, hoisting capacity, type of rigs, and crew efficiency. BSEE is not aware of any analysis of offshore operations that provides reasonable estimates of average trip time that could be used for the purpose of this calculation. In addition, it is common practice in the Gulf of Mexico (GOM) to perform BOP tests earlier than the required interval whenever operational opportunities become available *(i.e.*, whenever there is no drill pipe across the BOPs due to the need to change drill bits). This practice would reduce the overall benefit from this alternative. BSEE requests comments and data on both of these issues to assist in the assessment of the overall benefits of this alternative.

b. Potential reductions in oil spills

The proposed rule would result in benefits to society by reducing the probability of incidents involving oil spills. To estimate the benefits associated with the potential risk reduction of oil spills, we estimated the costs associated with an oil spill related to natural resource damages, the value of lost hydrocarbons, spill containment and cleanup, lost recreation opportunities, and impacts to commercial fishing. The magnitude of these benefits, however, is dependent on the effectiveness of the proposed

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[37] These estimates are based on the following calculations: for subsea rigs, (9 tests saved per year) x (20 hours per test) x (1 day/24 hours) x ($1 million/day) x 40 rigs = $300,000,000.; for surface BOP rigs, (9 tests saved per year) x (20 hours per test) x (1 day/24 hours) x ($200,000/day) x 50 rigs = $75,000,000.

[38] Trip time refers to the time needed to stop drilling or workover operations, remove or raise the drill/work string from the well, and then lower the string back to the bottom of the well to restart operations. A trip is often made to change a dull drill bit and/or to perform the pressure test or BOP test. During some deep drilling situations, the trip time may equal or exceed the on-bottom drilling time.

rule in reducing the number of incidents, which is uncertain. We thus conducted analysis to estimate the monetized net benefits (the difference between total benefits and total costs) from the reduction in oil spills for a variety of risk reduction levels, from 1 to 20 percent, that could potentially be achieved by the proposed rule.

Although common in situations where regulatory benefits are highly uncertain, we did not conduct a break-even analysis to estimate the minimum risk reduction the proposed rule would need to achieve in order for the rule to be cost-beneficial. This is because the rule is already cost-beneficial from the savings in operating costs under proposed section 250.737 (d)(10). In other words, the break-even risk reduction level of the proposed rule is 0 percent, indicating that the proposed rule would be cost-beneficial even if it does not achieve any reductions in the risk of oil spills. (The same is true of Alternative 2, which would have even greater time-savings benefits, as discussed above.)

In addition to the time savings and risk reduction benefits presented above, the proposed rule also has other benefits. Due to difficulties in measuring and monetizing these benefits, we do not offer a quantitative assessment of them. BSEE has used a conservative approach in the valuation of a catastrophic oil spill, including only selected costs of such a spill. For example, although we capture the environmental damage associated with a catastrophic oil spill, the analysis is limited because it only considers the environmental amenities that researchers could identify and monetize. Therefore, the resulting benefits of avoiding such a spill should be considered as a lower-bound estimate of the true benefit to society that results from decreasing the risk of oil spills. BSEE followed the approach used in the Case Study and sought to avoid double-counting the costs of a catastrophic event.

i. Benefits Data

To estimate the potential benefits of the proposed rule associated with reducing the risk of incidents, we examined historical data from the BSEE oil spill database, which contains information for spills greater than 10 barrels of oil for the Gulf of Mexico and Pacific regions. Based upon an analysis of the BSEE oil spill database during the period between 1964 and 2010,[39] BSEE identified 27 blowouts associated with oil spills greater than 10 barrels[40] and used this data within the economic analysis (see the initial RIA for details). Blowouts that resulted in uncontrolled flow of gas, damage to a rig, and/or harm to personnel (but not oil spills over 10 barrels) are not reflected in this analysis[41]. Accordingly, the benefits and the overall risk reduction associated with this proposed rule are likely understated. BSEE is specifically soliciting comments on any data and costs associated with any blowout that did not result in an oils spill greater than 10 barrels, and how to include that information within the economic analysis.

ii. Methods

We assumed that the proposed rule would reduce the likelihood of all oil spills, regardless of the size of the spill. We therefore applied a uniform probability distribution to take this assumption into account. We assumed a 1 percent risk reduction because it represents BSEE's best judgment of the causes of risk without the proposed rule and how those causes of risk would be affected by it.[42] Thus,

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[39] BSEE based the analysis on the historical oil spill database for the period between 1964 and 2010, but recognizes that significant regulatory and technological improvements have taken place since 1964. Limiting the analysis period to 1988 (the year when the most recent comprehensive overhaul of the Department of the Interior's offshore regulatory program took place) through 2010, and assuming a 1 percent risk reduction, would increase 10-year net benefits (including avoided fatalities) by $51,230,511 and $42,182,077 (with 3 percent and 7 percent discounting, respectively). The increase in the total net benefits from starting the analysis at such a later point results from the proportionately greater influence of the damages of the *Deepwater Horizon* incident on the estimated benefits of the proposed rule during that shorter timeframe.

[40] Source: http://www.bsee.gov/Inspection-and-Enforcement/Accidents-and-Incidents/Spills/.

[41] Previous Minerals Management Service studies indicate a total of 126 blowouts during drilling operations on the OCS between 1971 and 2006. These blowouts resulted in 26 fatalities, 63 injuries, damage to facilities and equipment, and the release of hydrocarbons.

[42] Several recent studies have estimated the probabilities of blowout failures under a wide range of circumstances. *See, e.g.,* "Blowout Preventer (BOP) Failure Event and Maintenance, Inspection and Test (MIT) Data Analysis for the Bureau of Safety and Environmental Enforcement (BSEE)," American Bureau of Shipping and ABSG Consulting Inc., (under BSEE contract M11PC00027), June 2013; "Improved Regulatory Oversight Using Real-Time Data Monitoring Technologies in the Wake of Macondo," K. Carter, U. of Texas at Austin, 2014, published with E. van Oort and A. Barendrecht, Soc'y of Petroleum Engineers, 2014; "*Deepwater Horizon* Blowout Preventer Failure Analysis Report to the U.S. Chemical Safety and Hazard Investigation Board," Engineering Services, LP, 2014. Given this accumulated knowledge of failure likelihoods under various circumstances, and analysis of how those

the 1 percent risk reduction represents the lower bound of the potential benefits of the proposed rule. Nevertheless, we present a sensitivity analysis on the assumed risk reduction level in section 9.a below.

To calculate the expected annual reduction in barrels of oil spilled associated with the proposed rule, we multiplied the annual number of spilled barrels (the total number of barrels spilled in the incident divided by 46.945 years) by 1 percent to calculate the expected annual reduction in barrels of oil spilled associated with the proposed rule. Exhibit 3 displays the calculation of the expected annual reductions in barrels of oil spilled assuming a 1-percent risk reduction resulting from the proposed rule.

EXHIBIT 3: CALCULATIONS OF NUMBER OF BARRELS SPILLED (AT A 1-PERCENT RISK REDUCTION FROM THE PROPOSED RULE)

Incident Rank (a)	Barrels of Oil Spilled (b)	Annualized Barrels (c = b ÷ 46.945 years)	Adjusted Risk Reduction (d = 1%)	Reduced Barrels (e = c * d)
27	10	0.2	1.00%	0.0
27	10	0.2	1.00%	0.0
27	10	0.2	1.00%	0.0
24	11	0.2	1.00%	0.0
23	25	0.5	1.00%	0.0
22	50	1.1	1.00%	0.0
21	60	1.3	1.00%	0.0
20	62	1.3	1.00%	0.0
19	64	1.4	1.00%	0.0
18	75	1.6	1.00%	0.0
17	100	2.1	1.00%	0.0
17	100	2.1	1.00%	0.0
15	125	2.7	1.00%	0.0
14	200	4.3	1.00%	0.0

likelihoods would be reduced by the proposed rule, BSEE has determined that 1 percent is a reasonable lower-bound of risk reduction that could occur as a result of the proposed rule, although in BSEE's expert opinion, the actual risk reduction from the proposed rule will likely be substantially higher than 1 percent.

14	200	4.3	1.00%	0.0
12	350	7.5	1.00%	0.1
11	450	9.6	1.00%	0.1
10	774	16.5	1.00%	0.2
9	1,061	22.6	1.00%	0.2
8	1,688	36.0	1.00%	0.4
7	2,500	53.3	1.00%	0.5
6	5,100	108.6	1.00%	1.1
5	5,180	110.3	1.00%	1.1
4	53,000	1,129.0	1.00%	11.3
3	65,000	1,384.6	1.00%	13.8
2	80,000	1,704.1	1.00%	17.0
1	4,928,100	104,975.5	1.00%	1049.8
Total Annual Reduced Barrels				**1,096**[1]

[1] Totals may not add because of rounding.

A risk reduction of 1 percent leads to an annual reduction of 1,096 spilled barrels. (See the appendix for the number of spilled barrels associated with each incident.) To estimate the benefits from a reduction in oil spilled, we multiplied the estimated annual reduction in spilled barrels of oil by the social and private cost of a spilled barrel of oil, which is estimated at $3,599. We derived this estimate from the "Economic Analysis Methodology for the Five Year OCS Oil and Gas Leasing Program for 2012-2017" (the "BOEM Case Study"),[43] and this value includes costs associated with natural resource damages, the value of lost hydrocarbons, and spill cleanup and containment.[44] Natural resource damages relate to the natural resources on the OCS that would be damaged by an oil spill. The value of the lost hydrocarbons reflects the lost usable oil. Finally, spill containment and cleanup costs include all the resources (capital and labor) needed to contain the spill and clean up the site. These costs are all included in the social cost of a barrel of oil, as per the directive of OMB Circular A-4 to include costs

[43] U.S. Department of the Interior. Bureau of Ocean Energy Management (2012), available at http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Leasing/Five_Year_Program/2012-2017_Five_Year_Program/PFP%20EconMethodology.pdf.

[44] The BOEM Case Study presents per-barrel costs associated with a catastrophic event. We use this estimate because the BOEM Case Study represents a recent estimate for the costs associated with an oil spill that includes data from the *Deepwater Horizon* incident.

regardless of where, when, or to whom the costs accrue.[45] We assumed a natural resource damage cost of $642 per barrel and a cleanup and containment cost of $2,857 per barrel as estimated for the Gulf of Mexico in the BOEM Case Study. Consistent with the BOEM Case Study, we used a value of lost hydrocarbon per barrel of $100, which is the value applied across all regions analyzed in the BOEM Case Study. We recognize the uncertainty associated with projecting the price of oil during the 10-year period of analysis and present a sensitivity analysis in section 9.c.

We also accounted for one-time costs associated with catastrophic oil spills.[46] Consistent with the BOEM Case Study, we assumed losses associated with recreation of $199 million per catastrophic incident and losses for commercial fishing of $13 million per incident. The BOEM Case Study estimated these costs on a per-incident basis because these costs are not dependent on the volume of oil spilled.[47] Historical data includes one catastrophic incident over the course of the past 46.945 years. We estimated an annual loss associated with recreation and commercial fishing due to catastrophic events of $4,515,899 (($212,000,000 per incident) x (1 incident/46.945 years)). We assumed a 1 percent risk reduction associated with these per-incident costs, resulting in an estimated annual risk reduction of $45,159.

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[45] Using both natural resource damages and containment and cleanup costs is consistent with the natural resource damages assessment methods described in the BOEM Case Study. This also accounts for any temporal or spatial distribution in the accrual of cleanup costs. For example, the cleanup on the coast may occur at a later time and different place than the initial spill.

[46] The BOEM Case Study defines a catastrophic oil spill in the GOM as one ranging in size from 900,000 barrels to 7,200,000 barrels.

[47] The BOEM Case Study presents seven separate cost categories to estimate the impact of a catastrophic spill, including natural resource damages, and impacts on recreation and commercial fishing. The natural resource damage cost associated with each barrel of oil spilled (expressed as a per-barrel cost) accounts for the damage (*e.g*. to wildlife, habitats, and ecosystems) caused by the oil itself as well as by cleanup crews. . Additional costs associated with catastrophic oil spills that are not represented in this per-barrel natural resource damage cost Include costs to commercial fishing (*i.e.,* economic losses due to fishery closures during a catastrophic oil spill and lost recreational values (based on the average number of trips and the value for each recreation trip).

The annual benefit from the reduction in spilled barrels of oil and the adjusted one-time costs of a catastrophic event is estimated at $4.0 million.

8. Analysis results

Exhibit 4 displays the monetized costs to industry and BSEE, as well as the total costs for each year and for the 10-year analysis period. The 10-year undiscounted total cost of the proposed rule is $883.2 million with $881.9 million of the total cost falling on industry and $1.3 million on BSEE. The discounted total costs for the 10-year period are $763.4 and $639.9 million at 3 and 7 percent discounting, respectively.

Exhibit 5 displays the monetized benefits for both time savings (under Section 250.737(d)(10) and under Section 250.447(b) for Alternative 2) and the risk reduction of oil spills for each year and for the 10-year analysis period. The 10-year total benefits for Alternative 1, the proposed rule, are $1,313.6 million and $1,081.6 million at 3 and 7 percent discounting, respectively, with the majority of the *quantified* benefits under Alternative 1 stemming from time-savings benefits under Section 250.737(d)(10). The discounted 10-year benefits for Alternative 2 are $4,512.4 million and $3,715.4 million at 3 and 7 percent discounting, respectively, with the majority of *quantified* benefits under Alternative 2 stemming from time-savings benefits under Section 250.477(b).

EXHIBIT 4: SUMMARY OF MONETIZED COSTS[1]

Year		Industry Costs	Government Costs (2012 dollars/year)	Total Costs
1	**2015**	$164,728,509	$134,273	$164,862,782
2	**2016**	$77,297,317	$134,273	$77,431,590
3	**2017**	$77,297,317	$134,273	$77,431,590
4	**2018**	$77,297,317	$134,273	$77,431,590
5	**2019**	$77,297,317	$134,273	$77,431,590

6	**2020**	$98,797,317	$134,273	$98,931,590
7	**2021**	$77,297,317	$134,273	$77,431,590
8	**2022**	$77,297,317	$134,273	$77,431,590
9	**2023**	$77,297,317	$134,273	$77,431,590
10	**2024**	$77,297,317	$134,273	$77,431,590
Undiscounted 10-year total		**$881,904,358**	**$1,342,732**	**$883,247,090**
10-Year Total with 3% discounting		**$762,252,353**	**$1,145,377**	**$763,397,731**
10-Year Total with 7% discounting		**$638,941,758**	**$943,078**	**$639,884,837**
10-year Average		**$88,190,436**	**$134,273**	**$88,324,709**
Annualized with 3% discounting		**$89,359,230**	**$134,273**	**$89,493,503**
Annualized with 7% discounting		**$90,970,932**	**$134,273**	**$91,105,205**

[1] Totals may not add because of rounding.

Because we are not able to monetize all of the consequences of an oil spill (and conversely, the benefits of avoiding such a spill), the risk reduction estimates we present reflect only a portion of the total value to society from reducing the risk of a spill. These estimates are assumed to be lower-bound estimates for the true benefit to society arising from a reduction in the risk of oil spills.

EXHIBIT 5: SUMMARY OF MONETIZED BENEFITS (AT A 1-PERCENT RISK REDUCTION FROM THE PROPOSED RULE)[1]								
Year		Alternative 1 - 250.737(d)(10) (subsea rigs)[2]	Alternative 1 - 250.737(d)(10) (surface rigs)[2]	Alternative 2 - 250.447(b) (subsea rigs)[3]	Alternative 2 - 250.447(b) (surface rigs)[3]	Risk Reduction Benefits	Total Benefits (Alternative 1)	Total Benefits (Alternative 2)
					(2012 dollars/year)			
1	**2015**	$120,000,000	$30,000,000	$300,000,000	$75,000,000	$3,988,977	$153,988,977	$528,988,977
2	**2016**	$120,000,000	$30,000,000	$300,000,000	$75,000,000	$3,988,977	$153,988,977	$528,988,977
3	**2017**	$120,000,000	$30,000,000	$300,000,000	$75,000,000	$3,988,977	$153,988,977	$528,988,977
4	**2018**	$120,000,000	$30,000,000	$300,000,000	$75,000,000	$3,988,977	$153,988,977	$528,988,977
5	**2019**	$120,000,000	$30,000,000	$300,000,000	$75,000,000	$3,988,977	$153,988,977	$528,988,977
6	**2020**	$120,000,000	$30,000,000	$300,000,000	$75,000,000	$3,988,977	$153,988,977	$528,988,977
7	**2021**	$120,000,000	$30,000,000	$300,000,000	$75,000,000	$3,988,977	$153,988,977	$528,988,977
8	**2022**	$120,000,000	$30,000,000	$300,000,000	$75,000,000	$3,988,977	$153,988,977	$528,988,977
9	**2023**	$120,000,000	$30,000,000	$300,000,000	$75,000,000	$3,988,977	$153,988,977	$528,988,977
10	**2024**	$120,000,000	$30,000,000	$300,000,000	$75,000,000	$3,988,977	$153,988,977	$528,988,977
Undiscounted 10-year total		**$1,200,000,000**	**$300,000,000**	**$3,000,000,000**	**$750,000,000**	**$39,889,771**	**$1,539,889,771**	**$5,289,889,771**
10-Year Total with 3% discounting		**$1,023,624,340**	**$255,906,085**	**$2,559,060,851**	**$639,765,213**	**$34,026,784**	**$1,313,557,210**	**$4,512,383,273**
10-Year Total with 7% discounting		**$842,829,785**	**$210,707,446**	**$2,107,074,462**	**$526,768,616**	**$28,016,906**	**$1,081,554,137**	**$3,715,397,215**
10-year Average		**$120,000,000**	**$30,000,000**	**$300,000,000**	**$75,000,000**	**$3,988,977**	**$153,988,977**	**$528,988,977**
Annualized with 3% discounting		**$120,000,000**	**$30,000,000**	**$300,000,000**	**$75,000,000**	**$3,988,977**	**$153,988,977**	**$528,988,977**
Annualized with 7% discounting		**$120,000,000**	**$30,000,000**	**$300,000,000**	**$75,000,000**	**$3,988,977**	**$153,988,977**	**$528,988,977**

[1] Totals may not add because of rounding.

2 Amounts include timesaving benefits of pressure testing and trip time associated with increasing BOP testing interval for completions and workovers from 7 to 14 days.

3 Amounts include timesaving benefits of pressure testing associated with increasing testing intervals for all BOPS (drilling, completions, workovers) from 14 to 21 days. This estimate does not include trip time.

Exhibit 6 summarizes the net benefits at a 1 percent risk reduction. The total 10-year net benefits for Alternative 1 are $550.2 million and $441.7 million at 3 and 7 percent discounting, respectively. The 10-year net benefits for Alternative 2 are $3,749.0 million and $3,075.5 million at 3 and 7 percent discounting, respectively.

EXHIBIT 6: SUMMARY OF NET BENEFITS (AT A 1-PERCENT RISK REDUCTION FROM THE PROPOSED Rule)[1]						
Year		Total Benefits (Alternative 1)	Total Benefits (Alternative 2)	Total Costs[2]	Net Benefits (Alternative 1)	Net Benefits (Alternative 2)
				(2012 dollars/year)		
1	**2015**	$153,988,977	$528,988,977	$164,862,782	($10,873,805)	$364,126,195
2	**2016**	$153,988,977	$528,988,977	$77,431,590	$76,557,387	$451,557,387
3	**2017**	$153,988,977	$528,988,977	$77,431,590	$76,557,387	$451,557,387
4	**2018**	$153,988,977	$528,988,977	$77,431,590	$76,557,387	$451,557,387
5	**2019**	$153,988,977	$528,988,977	$77,431,590	$76,557,387	$451,557,387
6	**2020**	$153,988,977	$528,988,977	$98,931,590	$55,057,387	$430,057,387
7	**2021**	$153,988,977	$528,988,977	$77,431,590	$76,557,387	$451,557,387
8	**2022**	$153,988,977	$528,988,977	$77,431,590	$76,557,387	$451,557,387
9	**2023**	$153,988,977	$528,988,977	$77,431,590	$76,557,387	$451,557,387
10	**2024**	$153,988,977	$528,988,977	$77,431,590	$76,557,387	$451,557,387
Undiscounted 10-year total		**$1,539,889,771**	**$5,289,889,771**	**$883,247,090**	**$656,642,682**	**$4,406,642,682**
10-Year Total with 3% discounting		**$1,313,557,210**	**$4,512,383,273**	**$763,397,731**	**$550,159,479**	**$3,748,985,543**
10-Year Total with 7% discounting		**$1,081,554,137**	**$3,715,397,215**	**$639,884,837**	**$441,669,301**	**$3,075,512,378**
10-year Average		**$153,988,977**	**$528,988,977**	**$88,324,709**	**$65,664,268**	**$440,664,268**
Annualized with 3% discounting		**$153,988,977**	**$528,988,977**	**$89,493,503**	**$64,495,474**	**$439,495,474**
Annualized with 7% discounting		**$153,988,977**	**$528,988,977**	**$91,105,205**	**$62,883,772**	**$437,883,772**

[1] Totals may not add because of rounding.

[2] This is a lower-bound estimate of the costs of this provision; BSEE seeks comment on costs that we were unable to estimate.

BSEE has concluded that after consideration of the impacts of the NPRM, the societal benefits of the proposed rule justify the societal costs.

9. Sensitivity Analysis

This section presents sensitivity analyses of the potential benefits of the proposed rule that could result from varying the following factors:

a. The level of risk reduction of oil spills achieved by the proposed rule

b. The level of risk reduction of fatalities achieved by the proposed rule

c. The price of a barrel of oil (i.e., the value of lost hydrocarbons)

These sensitivity analyses are presented for Alternative 1, the proposed rule.

a. Reduction in the Risk of Oil Spills

We thus far have assumed a 1 percent reduction in the annual risk of oil spills resulting from this proposed rule because it represents the lower bound estimate of the benefits of the rule based on BSEE's expert judgment. The benefits, and thus net benefits, of this proposed rule would differ under other assumed levels of reduction in the risk of oil spills. Exhibit 7 presents the total 10-year risk reduction benefits, total benefits (includes cost savings from changes in testing frequency),, and net benefits under a range of possible annual risk reduction levels for oil spills from 0 to 20 percent.

EXHIBIT 7: SUMMARY OF NET BENEFITS UNDER DIFFERENT RISK REDUCTION LEVELS[1]								
Annual Risk Reduction	Annual Benefits	Total 10-Year Risk Reduction Benefits (7% Discounting)	Total 10-Year Risk Reduction Benefit (3% Discounting)	Total 10-Year Benefits (7% Discounting)	Total 10-Year Benefit (3% Discounting)	Total 10-Year Net Benefits (Undiscounted)	Total 10-Year Net Benefit (7% Discounting)	Total 10-Year Net Benefit (3% Discounting)
0%	$0	$0	$0	$1,053,537,231	$1,279,530,426	$616,752,910	$413,652,394	$516,132,695
1%	$3,988,977	$28,016,906	$34,026,784	$1,081,554,137	$1,313,557,210	$656,642,682	$441,669,301	$550,159,479
2%	$7,977,954	$56,033,812	$68,053,568	$1,109,571,044	$1,347,583,994	$696,532,453	$469,686,207	$584,186,263
3%	$11,966,931	$84,050,719	$102,080,353	$1,137,587,950	$1,381,610,778	$736,422,225	$497,703,113	$618,213,047
4%	$15,955,909	$112,067,625	$136,107,137	$1,165,604,856	$1,415,637,562	$776,311,996	$525,720,019	$652,239,832
5%	$19,944,886	$140,084,531	$170,133,921	$1,193,621,762	$1,449,664,346	$816,201,768	$553,736,926	$686,266,616
6%	$23,933,863	$168,101,437	$204,160,705	$1,221,638,669	$1,483,691,131	$856,091,539	$581,753,832	$720,293,400
7%	$27,922,840	$196,118,344	$238,187,489	$1,249,655,575	$1,517,717,915	$895,981,311	$609,770,738	$754,320,184
8%	$31,911,817	$224,135,250	$272,214,273	$1,277,672,481	$1,551,744,699	$935,871,082	$637,787,644	$788,346,968
9%	$35,900,794	$252,152,156	$306,241,058	$1,305,689,387	$1,585,771,483	$975,760,854	$665,804,551	$822,373,752
10%	$39,889,771	$280,169,062	$340,267,842	$1,333,706,294	$1,619,798,267	$1,015,650,625	$693,821,457	$856,400,537
11%	$43,878,749	$308,185,969	$374,294,626	$1,361,723,200	$1,653,825,051	$1,055,540,397	$721,838,363	$890,427,321
12%	$47,867,726	$336,202,875	$408,321,410	$1,389,740,106	$1,687,851,836	$1,095,430,168	$749,855,269	$924,454,105
13%	$51,856,703	$364,219,781	$442,348,194	$1,417,757,012	$1,721,878,620	$1,135,319,939	$777,872,176	$958,480,889
14%	$55,845,680	$392,236,687	$476,374,978	$1,445,773,919	$1,755,905,404	$1,175,209,711	$805,889,082	$992,507,673
15%	$59,834,657	$420,253,594	$510,401,763	$1,473,790,825	$1,789,932,188	$1,215,099,482	$833,905,988	$1,026,534,457
16%	$63,823,634	$448,270,500	$544,428,547	$1,501,807,731	$1,823,958,972	$1,254,989,254	$861,922,894	$1,060,561,242
17%	$67,812,611	$476,287,406	$578,455,331	$1,529,824,637	$1,857,985,756	$1,294,879,025	$889,939,801	$1,094,588,026
18%	$71,801,589	$504,304,312	$612,482,115	$1,557,841,544	$1,892,012,541	$1,334,768,797	$917,956,707	$1,128,614,810
19%	$75,790,566	$532,321,219	$646,508,899	$1,585,858,450	$1,926,039,325	$1,374,658,568	$945,973,613	$1,162,641,594
20%	$79,779,543	$560,338,125	$680,535,683	$1,613,875,356	$1,960,066,109	$1,414,548,340	$973,990,519	$1,196,668,378

[1] For Alternative 1, the proposed rule.

Based on this analysis, the net benefits of the proposed rule are more sensitive to the percent reduction in the annual risk of oil spills than the other parameters evaluated within this RIA. As can be seen in Exhibit 7, the larger the risk reduction, the larger the net benefits. For example, 10-year total net benefits are $441.7 million and $550.2 million at a 1 percent risk reduction and $974.0 million and $1,196.7 million at a 20 percent risk reduction, at 7 and 3 percent discounting, respectively.

b. Reduction in the Risk of Fatalities

In addition to the time savings and the prevention of oil spills, the proposed rule is anticipated to reduce the risk of premature death of rig workers. The oil and gas extraction industry is characterized by a relatively small percentage of the national workforce, but with a fatality rate that is higher than for most industries. The fatality rate for oil and gas extraction workers is 23.9 fatalities per 100,000 full-time equivalent workers (Exhibit 8).

EXHIBIT 8: SELECTED OCCUPATIONAL FATALITY RATES BY INDUSTRY, 2008

Industry	**Fatality Rate** (per 100,000 Full-Time Equivalent Workers)
Agriculture, forestry, fishing, and hunting	30.4
Oil and gas extraction	23.9
Transportation and warehousing	14.9
Construction	9.7
Protective service occupations (includes protective service occupations such as fire fighters, and law enforcement)	9.1
Manufacturing	2.5
Management, professional, and related occupations	1.6
Finance, insurance, and real estate and leasing	1.1

Source: Bureau of Labor Statistics, 2010.

The economic benefits of occupational risk reduction are often measured using the *value of a statistical life* (VSL). The VSL concept is based on individual willingness to pay for reductions in small risks of premature death. In concept, the VSL measures the sum of society's willingness to pay for one unit of reduction in the risk of a fatality.

A large number of VSL estimates can be found in the academic literature. Published literature has included either explicit or implicit valuation of fatality risks and generally derives VSL estimates from studies on wage compensation for occupational hazards, on consumer product purchase and use decisions, or from using stated preference approaches. These values have varied over time, geographic locations, and worker heterogeneity. In the early 1980s, VSL estimates ranged from less than $1 million to approximately $3 million and were used to assess policies that reduced worker fatality. More recent studies have replaced these estimates with values as high as $9 million. However, the literature based on estimates using U.S. labor market data typically shows a VSL in the range of $4 to $9 million.

The U.S. Environmental Protection Agency (EPA) recommends using a VSL value of $7.4 million ($2006), updated to the base year of the analysis, in all benefits analyses that seek to quantify mortality risk reduction regardless of the age, income, or other characteristics of the affected population. This approach was endorsed by EPA in its 2000 *Guidelines for Preparing Economic Analyses*. A recent report from the EPA's Science Advisory Board concluded that the available literature does not support adjustments of VSL for most factors. However, the panel did support adjustments to reflect changes in income,[48] inflation, and time lags in the occurrence of adverse health effects.

For the purpose this analysis, BSEE used a VSL of $8.4 million to estimate the avoided costs associated with a reduction in the fatality rate. This is the EPA-recommended estimate of $7.4 million

[48] EPA allows the adjustment of VSL based on increases in future income but not on cross-sectional differences in income.

updated to 2012 dollars. The EPA-recommended VSL was chosen for this analysis because of the lack of consensus in previous research on adjusting VSL values for occupational risk.

There are a number of ways to use the concept of VSL when estimating risk reduction benefits. Dividing the number of fatalities by the number of years provides the average number of fatalities per year. Dividing the number of fatalities by the number of barrels spilled over the analysis time period gives the average number of fatalities per barrel of oil spilled.

Between 1964 and 2010, there have been 27 blowouts with oils spills greater than 10 barrels. Only two of these events resulted in injuries or fatalities. Those two events are a 1984 blowout and the 2010 *Deepwater Horizon* incident that resulted in 4 and 11 fatalities, respectively. Based on the 46.945-year period from 1964 to 2010, the average number of fatalities was 0.320 annually (15 / 46.945). Using a VSL of $8,423,301, the average cost of fatalities is $2,691,423 per year (0.320 x $8,423,301). Therefore, each 1 percent reduction in the risk of a fatality results in a risk reduction benefit of $26,914 (1% x $2,691,423).[49] Exhibit 9 presents the resulting fatality risk reduction benefit across a range of risk reduction values from 0 to 20 percent as both annual and total 10-year (undiscounted and discounted) values.

Next, Exhibit 10 presents the effect on the net benefits of the proposed rule if the additional benefit of fatality risk reduction is considered. The exhibit presents the undiscounted and discounted 10-year total net benefits when fatality risk reduction is considered in addition to the benefits of the rule included in the economic analysis presented above. For example, at a 1 percent fatality risk reduction level, the 10-year total benefits are $229,584 and $189,034 at 3 and 7 percent discounting, respectively.

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[49] Note that this calculation likely understates the benefits associated with fatality risk reduction because blowouts that did not result in an oil spill greater than 10 barrels were not part of the database used for this analysis. Previous MMS studies indicate a total of 126 blowouts during drilling operations on the OCS between 1971 and 2006. These blowouts resulted in 26 fatalities, 63 injuries, damage to facilities and equipment, and the release of hydrocarbons. Accounting for any additional fatalities would increase the fatality risk reduction benefits.

Assuming a higher fatality risk reduction of 20 percent, 10-year total benefits are $4.59 and $3.78 million (at 3 and 7 percent discounting, respectively).

Exhibit 9: Summary of Monetized Benefits from Averted Fatalities					
Fatality Risk Reduction	Fatalities Averted	Annual Value	10-year Total		
			Undiscounted	3% Discounting	7% Discounting
0%	0.000	$0	$0	$0	$0
1%	0.003	$26,914	$269,142	$229,584	$189,034
2%	0.006	$53,828	$538,285	$459,168	$378,069
3%	0.010	$80,743	$807,427	$688,752	$567,103
4%	0.013	$107,657	$1,076,569	$918,335	$756,137
5%	0.016	$134,571	$1,345,712	$1,147,919	$945,171
6%	0.019	$161,485	$1,614,854	$1,377,503	$1,134,206
7%	0.022	$188,400	$1,883,996	$1,607,087	$1,323,240
8%	0.026	$215,314	$2,153,139	$1,836,671	$1,512,274
9%	0.029	$242,228	$2,422,281	$2,066,255	$1,701,309
10%	0.032	$269,142	$2,691,423	$2,295,839	$1,890,343
11%	0.035	$296,057	$2,960,565	$2,525,422	$2,079,377
12%	0.038	$322,971	$3,229,708	$2,755,006	$2,268,412
13%	0.042	$349,885	$3,498,850	$2,984,590	$2,457,446
14%	0.045	$376,799	$3,767,992	$3,214,174	$2,646,480
15%	0.048	$403,713	$4,037,135	$3,443,758	$2,835,514
16%	0.051	$430,628	$4,306,277	$3,673,342	$3,024,549
17%	0.054	$457,542	$4,575,419	$3,902,926	$3,213,583
18%	0.058	$484,456	$4,844,562	$4,132,509	$3,402,617
19%	0.061	$511,370	$5,113,704	$4,362,093	$3,591,652
20%	0.064	$538,285	$5,382,846	$4,591,677	$3,780,686

EXHIBIT 10: SUMMARY OF MONETIZED BENEFITS FROM AVERTED FATALITIES w/ NET BENEFITS[1]

Fatality Risk Reduction	Fatality Risk Reduction Benefit (Total 10-year)	Net Benefits of Proposed Rule Without Fatality Risk Reduction (at a 1-Percent Risk Reduction from the Proposed Rule) (Total 10-year)	Net Benefits of Proposed Rule With Fatality Risk Reduction (at a 1-Percent Risk Reduction from the Proposed Rule) (Total 10-year)		
	Undiscounted	Undiscounted	Undiscounted	3% Discounting	7% Discounting
0%	$0	$656,642,682	$656,642,682	$550,159,479	$441,669,301
1%	$269,142	$656,642,682	$656,911,824	$550,389,063	$441,858,335
2%	$538,285	$656,642,682	$657,180,967	$550,618,647	$442,047,369
3%	$807,427	$656,642,682	$657,450,109	$550,848,231	$442,236,403
4%	$1,076,569	$656,642,682	$657,719,251	$551,077,814	$442,425,438
5%	$1,345,712	$656,642,682	$657,988,393	$551,307,398	$442,614,472
6%	$1,614,854	$656,642,682	$658,257,536	$551,536,982	$442,803,506
7%	$1,883,996	$656,642,682	$658,526,678	$551,766,566	$442,992,541
8%	$2,153,139	$656,642,682	$658,795,820	$551,996,150	$443,181,575
9%	$2,422,281	$656,642,682	$659,064,963	$552,225,734	$443,370,609
10%	$2,691,423	$656,642,682	$659,334,105	$552,455,318	$443,559,644
11%	$2,960,565	$656,642,682	$659,603,247	$552,684,901	$443,748,678
12%	$3,229,708	$656,642,682	$659,872,390	$552,914,485	$443,937,712
13%	$3,498,850	$656,642,682	$660,141,532	$553,144,069	$444,126,746
14%	$3,767,992	$656,642,682	$660,410,674	$553,373,653	$444,315,781
15%	$4,037,135	$656,642,682	$660,679,817	$553,603,237	$444,504,815
16%	$4,306,277	$656,642,682	$660,948,959	$553,832,821	$444,693,849
17%	$4,575,419	$656,642,682	$661,218,101	$554,062,405	$444,882,884
18%	$4,844,562	$656,642,682	$661,487,244	$554,291,988	$445,071,918
19%	$5,113,704	$656,642,682	$661,756,386	$554,521,572	$445,260,952
20%	$5,382,846	$656,642,682	$662,025,528	$554,751,156	$445,449,986

[1] For Alternative 1, the proposed rule.

c. Value of lost hydrocarbons

As an additional sensitivity analysis, BSEE estimated the net benefits of the proposed rule for different assumptions on the value of lost hydrocarbons. In the analysis presented above, BSEE used $100 as the per-barrel value of lost hydrocarbons in the event of a spill. To reflect recent fluctuations in the price of a barrel of oil, BSEE also estimated the net benefits of the proposed rule under two alternative price scenarios during the 10-year analysis period: $50/barrel and $130/barrel. These prices reflect what BSEE currently anticipates using for planning purposes.

Comparing the results of these two scenarios with the net benefit estimates presented above in Exhibit 6 demonstrates the sensitivity of the analysis results to changes in the assumed per-barrel value of lost hydrocarbons. Exhibit 11 presents the net benefits of the proposed rule under three scenarios for the value of lost hydrocarbons: $50/barrel, $100/barrel, and $130/barrel. As shown in Exhibit 11, with 3 percent discounting, the 10-year total net benefits range from $549.7 to $550.4 million at per-barrel values of lost hydrocarbons of $50 and $130, respectively. This range can be compared to the net benefits estimated above in Exhibit 6 of $550.2 million when the per-barrel value of lost hydrocarbons is assumed to be $100.

Because the value of lost hydrocarbons is a small component of the costs of an oil spill, fluctuations in this value per barrel of oil result in very small changes to the net benefits of the proposed rule. A 50 percent decrease in the per-barrel value of lost hydrocarbons (from $100 to $50) results in a decrease in the net benefits of the proposed rule of only 0.08 percent. Alternately, a 30 percent increase in the per-barrel value of lost hydrocarbons (from $100 to $130) results in an increase in the net benefits of the proposed rule of only 0.05 percent.

Exhibit 11: Summary of Net Benefits under Three Oil Price Scenarios (at a 1-Percent Risk Reduction from the Proposed Rule)[1]				
	Year	**$50/Barrel**	**$100/Barrel**	**$130/Barrel**
			(2012 dollars/year)	
1	**2015**	($10,928,596)	($10,873,805)	($10,840,931)
2	**2016**	$76,502,597	$76,557,387	$76,590,262
3	**2017**	$76,502,597	$76,557,387	$76,590,262
4	**2018**	$76,502,597	$76,557,387	$76,590,262
5	**2019**	$76,502,597	$76,557,387	$76,590,262
6	**2020**	$55,002,597	$55,057,387	$55,090,262
7	**2021**	$76,502,597	$76,557,387	$76,590,262
8	**2022**	$76,502,597	$76,557,387	$76,590,262
9	**2023**	$76,502,597	$76,557,387	$76,590,262
10	**2024**	$76,502,597	$76,557,387	$76,590,262
Undiscounted 10-year total		**$656,094,777**	**$656,642,682**	**$656,971,425**
10-Year Total with 3% discounting		**$549,692,105**	**$550,159,479**	**$550,439,903**
10-Year Total with 7% discounting		**$441,284,475**	**$441,669,301**	**$441,900,196**
10-year Average		**$65,609,478**	**$65,664,268**	**$65,697,142**
Annualized with 3% discounting		**$64,440,684**	**$64,495,474**	**$64,528,349**
Annualized with 7% discounting		**$62,828,982**	**$62,883,772**	**$62,916,646**

[1] For Alternative 1, the proposed rule.

10. Probabilistic Risk Assessment

a. Overview

BSEE is considering various alternative approaches to estimating the potential benefits of the proposed rule. The benefits (and costs) of a proposed regulation are based on the difference between the baseline (*i.e.*, status quo) and the proposed regulation. In relation to safety, environmental, and security benefits, one approach to estimating the benefits is based on the amount of risk reduction (as previously discussed). In general, risk can be reduced in two distinct ways; by decreasing the probability of the event, and/or by decreasing the consequences of the event. The evaluation of the reduction in risk typically can be performed in either a deterministic or probabilistic approach.

Historically, BSEE has evaluated the reduction of risk based on a deterministic approach. However, as statistical models and information become more available, BSEE is evaluating other possibilities, including whether to move toward a probabilistic approach, in this regulation. A probabilistic approach may enhance and extends more traditional, approaches by: (1) allowing consideration of a broader set of potential challenges; (2) providing a logical means for prioritizing these challenges based on risk significance; and (3) allowing consideration of a broader set of resources to address these challenges. Probabilistic risk assessments have been used by some federal agencies including the U.S. Nuclear Regulatory Commission, Department of Homeland Security, and the National Aeronautics and Space Administration.

For this proposed regulation, BSEE is requesting comment on whether or not BSEE should use a probabilistic risk assessment (PRA), including statistical information (*e.g.*, failure rates of valves), probabilities, uncertainties, and assumptions that potentially could help inform BSEE's final decision on the proposed regulation. It is important to note that the basic PRA approach described below has not been peer-reviewed (as PRAs should be) and is being provided at this time for transparency and informational purposes and not as the basis for a decision.

The basic modeling tools of PRA are event trees and fault trees. Event trees describe initiating events that threaten the system (*e.g.*, a loss of well control) and map the progression of events as successive layers of safeguards are engaged. Fault trees can model the response of subsystems down to the component level. The modeling of PRA fault trees affords many insights into risk and reliability of the system, including how failures propagate through the system.

b. Event Trees

Offshore well drilling typically proceeds in a sequence of repetitive steps: drilling ahead with suitably dense mud to prevent fluid influx from the formations being penetrated; setting casing to enclose and reinforce the well segment just drilled before proceeding to drill a further segment with denser mud; cementing the casing that has just been set to secure it to the well wall and prevent any openings that could allow hydrocarbons to migrate upward in the well; setting various plugs to ensure wellbore stability, provide zonal isolation, and/or create a barrier to potential well kicks or losses of well control; and continually testing and monitoring parameters, such as pressure readings and flow volumes, to confirm that well integrity is maintained.

By consolidating this often complex sequence of steps into a few events, one could draw a very simple event tree.[50] For example, a failure of one or more barriers (*e.g.*, mud, casing, cement, plugs) if not recognized through integrity testing and rectified, and if the blowout preventer fails, could result in a complete loss of well control. It is important to note that such an event tree would not model actions after the significant uncontrolled escape of hydrocarbons (SUEH) to mitigate the consequences of the accident, even though the mitigation would affect the overall risk. Therefore, the consequences of the accident may differ depending on the accident progression both before and after SUEH.

c. Available Data

BSEE currently collects a variety of data that could be useful in modeling some risks. BSEE requires operators to report incidents under 30 CFR 250.188, and may subsequently investigate the incident according to the procedures specified at 30 CFR 250.191. BSEE also conducts scheduled and unscheduled on-site inspections of oil and gas operations at least once a year, documenting any

[50] For more information on how to develop and use event trees and fault tees in PRAs, *see generally* U.S. Nuclear Regulatory Commission, "Probabilistic Risk Assessment (PRA)," July 17, 2013, available at http://tinyurl.com/mefe7om; National Offshore Petroleum Safety and Environmental Management Authority, "Guidance Note: Hazardous Identification, N-04300-GN0107, Revision 5" (2012), available at http://www.nopsema.gov.au/assets/Guidance-notes/N-04300-GN0107-Hazard-Identification.pdf;. "Optimising Hazard Management by Workforce Engagement and Supervision," V. Trbojevic, Health and Safety Executive, United Kingdom Government (2008), available at http://www.hse.gov.uk/research/rrpdf/rr637.pdf .

Potential Incidents of Non-Compliance (PINC). PINCs help to determine whether a facility is operating up to standards, though the majority of PINCs are not precursors to a loss in well control and therefore would not be relevant for a risk model.

However, BSEE does not currently collect data that provides a comprehensive basis for a probabilistic risk model. In addition, BSEE is not aware of any current industry-wide efforts to collect data for such a purpose, although BSEE has requested that the Ocean Energy Safety Institute (OESI) develop a database related to equipment reliability that might provide useful information for the future development of a PRA. BSEE welcomes comments and suggestions on all potential sources of data that could be useful in developing probabilistic risk models for offshore oil and gas operations.

d. Questions

BSEE is interested in the public's views on the potential advantages and disadvantages to developing a PRA model for this rulemaking. We specifically seek comments on the following issues:

1) What would be the potential advantages and disadvantages if BSEE were to move to risk-informed decisions in this proposed rule through the use of methods such as PRAs and event trees?
2) Given that there are a significant number of offshore drilling operations with different types of rig construction and drilling plans, if BSEE were to use event trees in risk reduction assessments, how much detail would such event trees need so that they would be representative of the affected operators and best inform stakeholders and decision makers? Provide examples of benefits and costs of any suggested level of detail and explain why that detail would be appropriate.
3) Describe any completed, ongoing or planned activities, not associated with BSEE, that could provide information useful to the potential development of a PRA approach applicable to this

proposed rules, including any analyses identifying areas of significant risk or uncertainties. If so, provide timelines for the activity, if not already completed; indicate whether the activity will be peer-reviewed; and explain how it could be used in the potential development of a PRA approach.

4) In addition to the request already made by BSEE to OESI mentioned above, please describe any other planned or ongoing data collection efforts that could provide relevant information useful in the potential development of PRAs for offshore oil and gas activities? If there are no such efforts at this time, how could such a data collection program be developed?

5) What challenges and concerns would there be to industry providing data to inform and help BSEE decide whether to engage in PRA modeling? What are ways that the challenges and concerns could be mitigated?

Please provide data and studies, if possible, to support any comments.

11. UMRA

This proposed rule would not impose an unfunded Federal mandate on State, local, or tribal governments but would, if finalized, create a private-sector mandate that could require expenditures exceeding $100 million in a single year by offshore oil and gas companies operating on the OCS. The Initial RIA, the initial Regulatory Flexibility Act analysis for this proposed rule, and the proposed rule itself address applicable requirements of the UMRA, 2 U.S.C. 1501 *et seq*.

Among other things, the proposed rule, the Initial RIA, or the initial RFA must:

(1) Identify the provisions of the Federal law (OCSLA and OPA) under which this rule is being proposed;

(2) Includes a quantitative assessment of the anticipated costs to the private sector (i.e., expenditures on labor and equipment) of the proposed rule (sections 5 and 6 above); and

(3) Include qualitative and quantitative assessments of the anticipated benefits of the proposed rule (*see* section 7 above).

In addition, because all anticipated expenditures by the private sector analyzed in the Initial RIA and the initial RFA analysis would be borne by the offshore oil and gas industry, the Initial RIA and initial RFA analysis satisfy the UMRA requirement to estimate any disproportionate budgetary effects of the proposed rule on a particular segment of the private sector.

In addition, the Initial RIA describes BSEE's consideration of three major regulatory alternatives (section 3). BSEE has decided to move forward with this proposed rule, in lieu of the other alternatives, because those alternatives would not as efficiently or effectively address the concerns and recommendations that were raised regarding the safety of offshore oil and gas operations and the potential for another event with consequences similar to those of the *Deepwater Horizon* incident or achieve the objectives of this proposed rule.

BSEE has determined that the proposed rule would not impose any unfunded mandates or any other requirements on State, local, or tribal governments; thus, the proposed rule would not have disproportionate budgetary effects on these governments. Assuming, however, that the proposed rule results in budgetary effects, BSEE has determined that accurately estimating such effects is not reasonably feasible. Because the proposed rule would not impose any requirements on any entities, other than operators engaged in OCS offshore oil and gas activities, any budgetary effects would be at least secondary results of actions or decisions taken by regulated (or unregulated) entities, based on a variety of circumstances (such as the price of oil and each entities' overall financial health) at the time. Because each of those factors is variable and unpredictable, it is not feasible to estimate how those factors would affect an entity’s future decisions, or what impacts, if any, such decisions could have on future regional budgets.

Similarly, BSEE has determined that accurately estimating the potential effects, if any, of the proposed rule on the national economy (e.g., productivity, economic growth, employment, international competitiveness) is not reasonably feasible. Any potential impact on the national economy would depend on individual business decisions made by regulated entities (e.g., whether or not to hire new employees).

Appendix: List of Incidents Used in Benefits Analysis

Exhibit A-1 lists the oil spills used in the benefits analysis, including the date, total volume spilled (in barrels), and the number of fatalities for each incident. Spills presented in Exhibit A-1 include only incidents caused by blowouts from 1964 to 2010 that resulted in spills of 10 barrels of more. These data were obtained from the BOEMRE OCS Spill Database.

Exhibit A-1 : Incidents Used in Benefits Analysis

Date	Total Spilled (Barrels)	Fatalities
1964-01-20	100	0
1964-10-03	5,100	0
1964-10-03	5,180	0
1965-07-19	1,688	0
1969-01-28	80,000	0
1969-03-16	2,500	0
1970-02-10	65,000	0
1970-12-01	53,000	0
1971-05-16	10	0
1971-10-16	450	0
1974-09-07	75	0
1974-12-22	200	0
1981-11-28	64	0
1985-02-23	50	4
1987-03-20	60	0
1992-12-26	100	0
1999-09-09	125	0
2000-02-28	774	0
2002-10-03	350	0
2003-03-08	10	0
2004-10-21	11	0
2006-02-20	10	0
2006-11-18	25	0
2007-10-21	1,061	0
2009-04-19	200	0
2009-12-30	62	0
2010-04-20	4,928,100	11

Source: BOEMRE OCS Spill Database, June 2011.