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

Regulatory Impact Analysis

RIN: 1014-AA11

FINAL RULE

DEPARTMENT OF THE INTERIOR

Bureau of Safety and Environmental Enforcement

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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.

This final rule on Blowout Preventer Systems and Well Control is a “significant regulatory action” that is economically significant under section 3(f) of E.O. 12866. Accordingly, OMB has reviewed this regulation.

The Regulatory Flexibility Act (RFA) of 1980, 5 U.S.C. 601 *et seq*., requires agencies to consider the economic impact of regulatory changes on small entities. In addition, the Unfunded Mandates Reform Act of 1995 (UMRA) (Pub. 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 that may 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 rule, the Bureau of Safety and Environmental Enforcement (BSEE) provides the following summary:

(1) BSEE has determined that the 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 (the first) of the 10-year analysis period;

(2) BSEE has determined that the rule will have a “significant economic impact on a substantial number of small entities” under the RFA (5 U.S.C. § 605(b)); and

(3) In accordance with UMRA, BSEE has determined that this rule will not impose an unfunded mandate on State, local, or tribal governments of more than $100 million in a single year and will not have a significant or unique effect on State, local, or tribal governments. BSEE has also determined that this rule will impose costs on the private sector of more than $100 million in a single year. Although these costs do not appear to

trigger the requirement to prepare a written statement under UMRA, BSEE has chosen to prepare a written statement satisfying the applicable requirements of UMRA.

2. Need for regulation

BSEE has 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 this rule necessary to reduce the likelihood and/or severity of any oil or gas blowout, which can lead to the loss of life, serious injuries, and harm to the environment. As 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] The Federal Government and industry conducted multiple investigations to determine the causes 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 (*see* proposed rule, 80 FR 21508-21511 (April 17, 2015).)

[1] For example, any approximation of cost would incorporate the cost of catastrophic spills such as the *Deepwater Horizon* incident. BP estimates that its oil spill response and cleanup operations for the *Deepwater Horizon* incident cost more than $14 billion. In addition to oil spill response and cleanup costs, BP has agreed to pay over $14 billion to Federal, State, and local governments for natural resources damages, economic claims, and other expenses pursuant to a Consent Decree approved by the U.S. District Court for the Eastern District of Louisiana on April 4, 2016. BP currently estimates that it will pay $12.4 billion to private parties for business economic loss claims, and BP expects that the total amount that it will pay will significantly exceed the current estimate. Sources: *See* 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; summary of settlement agreement regarding natural resources damages available at www.doi.gov/deepwaterhorizon and at http://www.justice.gov/enrd/deepwater-horizon; approved Consent Decree available at https://www.justice.gov/opa/file/838231/download; BP p.l.c., Fourth Quarter 2015 Results, p. 19, available at http://www.bp.com/content/dam/bp/pdf/investors/bp-fourth-quarter-2015-results.pdf.

In addition, despite new regulations and improvements in industry standards and practices since the *Deepwater Horizon* incident, loss of well control (LWC) incidents are happening at about the same rate five years after that incident as they were before. Although progress has been made in other aspects of offshore safety and environmental protection, in 2013 and 2014 there were 8 and 7 LWC incidents per year, respectively – a rate on par with pre-*Deepwater Horizon* LWCs.[2]

As an 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 of industry's responses to the incident, and of subsequent incidents and blowouts, BSEE has determined that the requirements contained in this rule are necessary to fulfill BSEE's statutory responsibility to regulate offshore oil and gas operations and to enhance the safety of offshore exploration, production, and development. (*See* 43 U.S.C. 1347-1348; 30 CFR 250.101.) BSEE has also determined that the BOP regulations need to be updated to incorporate some of the more pertinent recommendations as discussed in the preambles to the proposed and final rules (*e.g.*, 80 FR 21508-21511), while others are being studied for consideration in future rulemakings. The rule creates a new Subpart G in 30 CFR Part 250 to consolidate the well-control requirements for drilling, completion, workover, and decommissioning operations. Consolidating these requirements will improve efficiency and consistency of the regulations and allow for flexibility

[2] *See* http://www.bsee.gov/uploadedFiles/BSEE/BSEE_Newsroom/Publications_Library/Annual_Report/BSEE%202014%20Annual%20Report.pdf. Some of these LWC incidents have resulted in blowouts, such as the 2013 Walter Oil and Gas incident that resulted in an explosion and fire on the rig, which was completely destroyed. *See* BSEE, DOI, *Investigation of Loss of Well Control and Fire South Timbalier Area Block 220, Well No. A-3 OCS-G24980 – 23 July 2013* (July 2015), at http://www.bsee.gov/uploadedFiles/BSEE/Enforcement/Accidents_and_Incidents/Panel_Investigation_Reports/ST%20220%20Panel%20Report9_8_2015.pdf.

in future rulemakings. The rule also revises existing provisions throughout Subparts D, E, F, and Q to address concerns raised in the investigations, BSEE's internal reviews, the public forum, and other input from stakeholders and the public. The rule also incorporates guidance from several NTLs and revises provisions related to drilling, workover, completion, and decommissioning operations to enhance safety and environmental protection.

3. Alternatives

BSEE has considered three regulatory alternatives:

(1) Promulgate the requirements contained in the proposed rule (*see* 80 FR 21504 (April 17, 2015)), including increasing the BOP pressure testing interval for workover and decommissioning operations from the current requirement of once every 7 days to once every 14 days. The following chart identifies the BOP pressure testing changes related to Alternative 1;

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

(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 pressure testing changes related to Alternative 2;

BOP Pressure Testing			
Operation	**Current Testing Frequency**	**New Testing Frequency**	**Alternative 2 Testing**

		(Alternative 1)	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

(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 as applicable to BOP systems.

By taking no regulatory action, Alternative 3, BSEE would leave unaddressed most of 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.[3]

Alternative 2 (changing the required frequency of BOP pressure testing to once every 21 days for all operations) was not selected because BSEE lacks critical data on testing frequency and equipment reliability to justify such a change at this time.

BSEE has elected to move forward with Alternative 1—the final rule—which incorporates recommendations provided by government, industry, academia, and other stakeholders and prior to the proposed rule by government, industry, academia, and other stakeholders. However, as discussed in detail in the preamble of the final rulemaking notice, the final rule does include certain revisions based on BSEE consideration of recommendations contained in public comments on the proposed rule, including incorporation of elements of American Petroleum

[3] *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.

Institute (API) Standard 53 and related standards. In addition to addressing concerns arising from the *Deepwater Horizon* incident and aligning with industry standards, BSEE is advancing several of the more critical well-control capabilities beyond current industry standards applicable to BOP systems agency knowledge, experience and technical expertise. The rule will also improve efficiency and consistency of the regulations and allow for flexibility in future rulemakings.

In the proposed rule, BSEE stated it was considering including an additional provision in the final rule that would require operators to install technology capable of severing any components of the drill string (excluding drill bits) within 10 years from publication of the final rule. (*See* 80 FR 21529.) BSEE invited public comments on key technical and economic issues that would help BSEE decide whether to include such a requirement in the final rule. Only a small number of comments addressed this severing issue, and none of the comments provided adequate relevant technical or economic data to help BSEE determine whether to include the requirement in the final rule. Therefore, BSEE has not included such a provision in the final rule. If, at a later date, BSEE decides to proceed with such a regulation, BSEE will propose to do so in a separate rulemaking notice.

4. Economic analysis

BSEE's economic analysis evaluated the expected impacts of the rule compared with the baseline. The baseline refers to current industry practice in accordance with existing regulations, industry permits, DWOPs, and industry standards with which operators already comply.[4] The

[4] 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. The industry standards relevant to this rule were developed by committees of industry members and others and subsequently approved by an industry standards development organization (*e.g.*, API).

baseline also refers to BSEE's and industry's current implementation of existing rules. Impacts that exist as part of the baseline were not considered costs or benefits of the rule. Specifically, the analysis excluded the following baseline components:

- Activities or capital investments required by existing regulations or as conditions for permits or DWOP approval.
- Activities with which operators already comply, such as voluntary industry standards, including those standards which the final rule incorporates.
- Any costs associated with current implementation of existing rules.

Thus, the cost analysis evaluates only activities and capital investments required by the rule that represent a change from the baseline. Appendix A presents a list of rule impacts that were considered part of the baseline and, therefore, were not included in the analysis.

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, and all costs and benefits are presented in 2014 dollars.

a. <u>Costs</u>

Section 5 below outlines how we quantified and monetized the costs of the rule. It identifies all of the provisions that will result in increased labor requirements or capital investments for industry or costs to BSEE. The costs discussed in this section, however, do not include reductions in costs (*i.e.*, cost savings) to industry that will also occur as a result of the final rule revising a prior regulatory requirement regarding pressure testing of certain BOPs. Those cost savings are discussed in the Benefits section of this analysis. In fact, as explained later in this analysis, the estimated cost savings from the final rule will exceed the estimated costs listed in this section; thus, industry should experience lower overall costs of operations as a net result of this rule. 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.[5]

The analysis covers 10 years (2016 through 2025) to ensure it encompasses the significant costs and benefits likely to result from the rule.[6] 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.[7]

BSEE received several comments on the initial regulatory impact analysis (RIA) for the proposed rule suggesting that the analysis period used in the initial RIA was insufficient to fully assess the impacts of the rule on OCS operations. Commenters noted, in particular, that offshore developments and equipment have lifecycles of 20 to 30 years, making the 10-year analysis period used in the RIA insufficient for estimating the costs and benefits of the rule. BSEE has determined, however, that the 10-year analysis period used in the RIA is appropriate to maintain reasonable certainty of the estimates, given the uncertainties that exist beyond 10 years with regard to industry activities, technological change, and energy markets.

[5] The monetized cost estimates in this analysis that are attributable to specific new requirements of the final rule may be somewhat overstated given that some of those requirements expressly permit potentially less costly alternatives (*e.g.*, final § 250.414(c)(2)), and that § 250.141 of the existing rules allows operators to request approval of equally protective – but potentially less costly - alternatives to required equipment or procedures.
[6] The initial economic analysis, which accompanied the proposed rule published in April 2015, also used a 10-year analysis period, from 2015 through 2024.
[7] We note that although a few provisions of the rule do not require compliance until 2, 3, 5 or 7 years after publication of the final year, this analysis estimates costs for all 10 years of the analysis period.

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 ambiguous results and therefore be disadvantageous in determining actual costs and benefits likely to result from this rule. BSEE concluded that this 10-year analysis period provides the best overall ability to forecast costs and benefits likely to result from this rule.

To summarize the costs of specific provisions, we present the estimated average annual cost as well as 10-year discounted totals (in 2014 dollars) 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 rule.

b. Benefits

Section 6 below presents the data, methodology, and results of the benefits analysis. We quantified and monetized the potential benefits of the rule, including time savings, reduction in oil spills, and reduction in fatalities. We estimated the benefits derived from time savings associated with § 250.737 of the rule, which streamlines BOP pressure testing for workovers and decommissioning. We also estimated time-savings benefits associated with a change in the required frequency of BOP pressure testing for all types of operations under Alternative 2, which would reduce the number of required BOP pressure tests per year (by reducing test frequency to once every 21 days). In addition, we estimated the benefits derived from the reduction in oil spills and fatalities using the incident-reducing potential of the rule as a whole.

We calculated the benefits under various risk-reduction scenarios, which allowed us to determine the cost-effectiveness of the rule (*i.e.*, whether the benefits justify the costs) depending on the percentage of potential oil spills and number of fatalities potentially prevented. Similar to the costs analysis, we estimated the potential benefits over a 10-year study period (2016 through 2025). The benefits are presented as 10-year discounted totals, that is, as the present value of the benefits (in 2014 dollars).

c. Transfers

We did not identify any transfer payments associated with the 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 will be affected by the 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 will remain constant over the 10-year analysis period. We believe the assumption of a constant number of rigs is reasonable on the basis of historical data.

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 (in 2014 dollars) 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 $62.53 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 estimated an average hourly wage rate of $21.28 for an administrative staff person. We estimated the average hourly wage rates of $40.00 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 $42.55 using data from the OPM: GS-12, step 5 average wage rate for the Houston metropolitan statistical area and the parish of Jefferson and cities of Lake Charles and Houma in Louisiana. We estimated the average hourly wage rate for a clerical staff to be $22.64 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 1.43 derived from the 2014 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).[8] We multiplied the average hourly wage rates by the appropriate loaded wage factor to estimate the following average hourly compensation rates:

- $89.42 for a mid-level industry engineer;
- $24.31 for an industry administrative staff;
- $57.20 for an industry rig crew staff;
- $57.20 for an industry technician;
- $67.85 for a mid-level BSEE engineer; and
- $38.25 for a BSEE clerical staff.

iii. Daily rig operating costs

Some requirements in the 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 estimated 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 (in 2014 dollars). We recognize that these figures can vary 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).[9] For the purposes of the analysis, we estimated that the

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

[9] 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,

daily rig operating costs, in constant 2014 dollars, 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 rule compared to the baseline. Both Alternative 1 (which would reduce the required frequency of BOP pressure testing to once every 14 days for workovers and decommissioning) and Alternative 2 (which would reduce the required frequency of BOP pressure testing to once every 21 days for all operations) would result in a time-savings benefit to industry and no additional costs to industry. The following requirements will result in a change from the baseline:

(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);

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and review of previously approved rates in published rulemakings. We assume that the daily cost estimate includes both the costs of leasing the rig and the salaries of the personnel that support those daily activities.

(i) Foundation requirements for MODUs;

(j) Real-time monitoring of well operations for rigs under certain circumstances (*e.g.*, rigs 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 organization (BAVO);[10]

(n) New surface BOP system requirements;

(o) New subsea BOP system requirements;

(p) New 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) Remotely operated vehicle (ROV) intervention function testing;

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

(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 (RTM);

(y) Industry familiarization with the new rule; and

(z) BAVO applications.

These requirements and their associated costs to industry and government are discussed in the sections that follow. As stated above, the costs discussed below do not include cost savings that will also occur as a result of the final rule. (Please also note that the descriptions of the rule provisions presented in this RIA seek to mirror the language of the final rule; however, only the regulatory text of the final rule is legally binding.)

BSEE received several comments on the initial RIA for the proposed rule indicating that some of the costs assumed to be part of the baseline (and, therefore, not considered costs of the rule) are either actually not current industry standard or not in accordance with existing regulations. Commenters cited activity reporting and recordkeeping; additional information to District Managers; BOP system testing; autoshear, deadman, and EDS systems; casing and cement requirements; maintenance and inspection requirements; packer and bridge plug inventory loss; redundant components for well control; ROV requirements; SCCE requirements; additional cement log runs; and containment services as examples of costs the analysis failed to consider because they were assumed to be part of the baseline.

BSEE established the baseline used in the initial RIA in accordance with the guidance provided by OMB Circular A-4 ("Regulatory Analysis"). This guidance is consistent with BSEE's determination that the baseline includes current industry practices as reflected in existing regulations, industry permits, DWOPs, notices to lessees, and industry standards with which operators already comply. Further, in a broader context, consistent with Circular A-4, BSEE has determined that the costs included in the baseline are appropriately categorized based on the current "state of the world" and the projected "state of the world" in the absence of the rule. The difference between the states of the world with and without the rule underlies the basis of the RIA. In contrast, many of the comments appeared to assume that any cost associated with new regulations is a cost of the rule regardless of whether those costs are already incurred in standard industry practice. This assumption is inconsistent with both OMB guidance on the preparation of the RIA and with the general principles upon which the RIA is based. Additional discussion of BSEE's development of the baseline scenario can be found in Section 4 and in Appendix A.

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

As discussed in detail in the preamble to the final rule, § 250.413(g) requires information on safe drilling margins to be included in the description of the well drilling design criteria. Safe drilling margins are 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 for BSEE to better review the well drilling design and drilling program.

The requirement to include information on the safe drilling margins in the well drilling design criteria results in increased labor costs for industry. We calculated the annual industry labor cost associated with this new requirement based on the time required per well to include the additional information in the well drilling criteria, the average hourly compensation rate for the staff most likely to complete this task, and the expected number of wells drilled per year, resulting in an estimated annual labor cost to industry for this documentation requirement of about $29,000.[11] No additional costs to BSEE are expected as a result of this requirement.

b. Additional information in the drilling prognosis

Section 250.414 requires industry to provide additional information in the drilling prognosis. New paragraph (j) requires 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 will provide BSEE with data to consider during the approval process and will 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 will 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 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

[11] We estimated that industry staff (mid-level engineer) will 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 will 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 ($89.42) and the average number of wells drilled per year to obtain an average annual labor cost to industry of $28,614.

requirement of about $7,200.[12] No additional costs to BSEE are expected as a result of this requirement.

BSEE received a comment that the additional information to be provided on wellhead systems due to this requirement would call for operators to include wellhead and liner hanger specifications in the APD, resulting in an additional cost to operators. BSEE notes, however, that this information is readily available from the original equipment manufacturer (OEM) once the operator purchases the wellheads, so the additional cost to operators due to these requirements should be minimal.

Some comments suggested that the costs in the RIA, under the proposed rule, should have included a higher cost for the requirement of safe drilling margins under § 250.414. The proposed rule specified that the static mud hole weight must be at least 0.5 pounds per gallon (ppg) below the minimum of the lowest estimated fracture gradient and the casing shoe pressure integrity test. After considering the comments, BSEE revised this requirement in the final rule to allow for alternative drilling margins (in lieu of 0.5 ppg), provided that the operator submits adequate documentation (such as risk modeling, off-set well, analog, or seismic data) to justify the alternative equivalent downhole mud weight. This is consistent with existing BSEE policy and industry practice, as discussed in Appendix A. As a result, the costs of these revised requirements generally fall into current industry practice, *i.e.*, they are part of the baseline, and the high costs of the proposed safe drilling margin have been removed from the costs of this rule.

[12] We estimated that industry staff (a mid-level engineer) will 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 ($89.42) and the average number of wells drilled per year (320) to obtain the average annual labor cost to industry of $7,153.

c. Prohibition of a liner as conductor casing

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

This provision will 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. For this requirement, the estimated total cost to industry of equipment and labor was $795,000.[13] No additional costs to BSEE are expected as a result of this requirement.

d. Additional capping stack testing requirements

Section 250.462 addresses source control and containment requirements. New paragraph (e)(1) details 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-containing critical components on a bi-annual basis. Under the former regulations, there was no

[13] 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 per year), based on input provided in submittals to BSEE. In order to calculate the average annual equipment costs, we estimated that the average cost of the casing joints and wellhead per well will be $65,000, resulting in a total equipment cost for three wells of $195,000. We estimated that industry staff (rig crew) will spend one extra day to install the new equipment on a well. Using the average labor cost for a rig crew per day ($200,000), we obtained an estimated average annual labor cost to industry of $600,000. Summing the equipment and labor costs yields a total average annual cost to industry of $795,000 for this requirement.

testing requirement for capping stacks. These new requirements help ensure that operators are able to control a subsea blowout.

These new testing requirements will result in new equipment and service costs to industry. We estimated the cost of testing for each capping stack, as revised based on industry comments on the proposed rule and initial RIA, 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 $226,200.[14] No additional costs to BSEE are expected as a result of these requirements.

As noted, some comments suggested that BSEE underestimated the costs of capping stack tests in the initial RIA of the proposed rule. BSEE analyzed these comments and agreed that the cost estimate should be revised upward. Using information provided in one of the comments, BSEE thus revised the cost estimate (to industry overall) from $80,000 per year to $226,000 per year (in 2014 dollars).

e. Additional information in the APM for installed packers

In Section 250.518, paragraphs (e) and (f) 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 new provisions codify existing BSEE policy to ensure consistent permitting. BSEE expects that operators already

[14] We estimated that the equipment and service costs of testing for capping stacks will be $14,138 per test, based on industry input. Additionally, we estimated that 4 capping stacks will 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 $226,200. We estimated that the required testing will 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.

comply with the design specifications included in this section, because they are based on an established industry standard; *i.e.*, American Petroleum Institute (API) Specification (Spec.) 11D1. Thus, the depth setting calculation is the only requirement that imposes a new cost beyond the baseline. The required calculations will be submitted for every well that is completed where tubing is installed.

The requirement to include additional information in the APM will 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 will be submitted each year. To calculate the new annual labor cost to BSEE, we multiplied the time that BSEE will 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 will be submitted each year. We estimated an average annual labor cost for this documentation requirement of about $5,800 to industry and about $4,400 to BSEE.[15]

BSEE received comments stating that the costs of this requirement should include costs associated with the requirements for tubing and wellhead equipment. BSEE notes, however, that

[15] We estimated that industry staff (a mid-level engineer) will spend 0.25 hours to include the additional information in the APM for a well. We estimated that APMs will 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 ($89.42) and by the estimated number of wells with installed packers for which an APM will be submitted each year to obtain an estimated average annual labor cost to industry of $5,812. We estimated that BSEE staff (a mid-level engineer) will 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 ($67.85) and by the estimated number of wells with installed packers for which an APM will be submitted each year to obtain an average annual labor cost to BSEE of $4,410.

these costs are part of the baseline because they are based on existing standards for tubing and wellhead equipment.

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

In Section 250.619, new paragraphs (e) and (f) 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 new requirements codify existing BSEE policy to ensure consistent permitting. BSEE expects that operators already comply with the design specifications included in this section, which incorporate an established industry standard (*i.e.*, API Spec 11D1). The depth-setting description and calculation is the only requirement that will impose a new cost beyond the baseline. The required calculations will be submitted for every well that is worked over where tubing is pulled and then reinstalled.

The requirement to include additional information in the APM will 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 (1,010) with pulled and reinstalled packers for which an APM will be submitted each year. To calculate the new annual labor cost to BSEE, we multiplied the time that BSEE will 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 will be submitted each year. These calculations resulted in average annual labor costs for this documentation requirement of about $23,000 to industry and $17,000 to BSEE.[16]

g. Rig movement reporting

Section 250.712 lists requirements for reporting movement of rig units to the BSEE District Manager. Revised paragraph (a) extends the rig movement reporting requirements to all rig units conducting operations covered under this subpart, including MODUs, platform rigs, snubbing units, and coiled tubing units. Paragraphs (c) and (e) are new and 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) is 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 will be required. Currently, movement reports are only required for drilling operations, but the new rule requires operators to submit movement reports for other operations as well, including when rigs are stacked or enter OCS waters. These changes will allow BSEE to better anticipate upcoming operations, locate MODUs and platform rigs in case of emergency, and verify rig fitness. The requirement to notify BSEE of rig unit movement will result in annual labor costs to industry of about $4,000 and to BSEE of $3,100.[17]

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[16] We estimated that industry staff (a mid-level engineer) will spend 0.25 hours to include the additional information in the APM for a well. We also estimated that APMs will 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 ($89.42) and the estimated number of wells with pulled and reinstalled packers for which an APM will be submitted each year to obtain an average annual labor cost to industry of $22,578. We estimated that BSEE staff (a mid-level engineer) will 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 ($67.85) and by the estimated number of wells with pulled and reinstalled packers for which an APM will be submitted each year to obtain an average annual labor cost to BSEE of $17,131.

[17] This is based on the assumption of an average of 60 reports per year, of which 50 require about 0.5 hours to prepare by industry (by a mid-level engineer at a compensation rate of $89.42 per hour), and 10 others requiring

h. Fitness requirements for MODUs

Section 250.713(a) adds a requirement that operators provide fitness information for a MODU for workovers, completions, and decommissioning. Operators must provide information and data to demonstrate the drilling unit's capability to perform at the new drilling location. This information must include the maximum environmental and operational conditions that the unit is designed to withstand, including the minimum air gap (where relevant) that is 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 may revoke the approval of the APD or APM if information collected during operations shows that the drilling unit is not capable of performing at the new location. These costs, in combination with the foundation requirements for MODUs, are discussed at the end of the next section.

i. Foundation requirements for MODUs

Section 250.713(b) introduces foundation requirements for MODUs performing workovers, completions, and decommissioning. Operators must provide information to show that site-specific soil and oceanographic conditions are capable of supporting the rig unit[18]. 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.

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about 2 hours to complete. We estimated that BSEE requires as much time to process and review the reports, by a mid-level BSEE engineer, at a compensation rate of $67.85 per hour.

[18] Soil sampling data is included in operators' exploration plan and deepwater operations plan submissions, and verified by BSEE in the APD process, under existing regulations.

The former regulations, and the new final rule, 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 rig's anchor patterns approved in the EP, DPP, or DOCD in the APD or APM.

This requirement will result in labor costs to industry and BSEE. To calculate the industry labor cost, we multiplied the time required to record and report the 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 will 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. We estimated these annual labor costs to be about $208,000 to industry and $158,000 to BSEE.[19]

j. Real-time monitoring of well operations

Section 250.724 is a new section that establishes requirements for:

(1) Real-time monitoring (RTM) of 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;

(2) Storing RTM data onshore; and

(3) Developing and implementing an RTM plan that addresses RTM capabilities and procedures.

[19] We estimated that an industry mid-level engineer will spend 5 hours on average per report, at a compensation rate of $89.42 per hour, and an average of 466 reports will be provided per year. We estimated that BSEE staff (a mid-level engineer) will spend 5 hours on average to review and process the information, at an average hourly compensation rate of $67.85 per hour.

In order to comply with this section, industry will incur annual equipment and labor costs associated with gathering, recording, transmitting, and storing data (as well as one-time labor costs to develop RTM plans).[20] 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 will engage in well operations per year (and will thus be subject to this monitoring requirement). We assumed that this type of service mostly lends itself to a day rate. Based on the cost per day per rig to perform the monitoring, the number of days per year that the rig will be engaged in well operations, and the number of rigs, we estimated the annual costs to industry to be $40.5 million.[21] Since RTM plans will only be available to BSEE upon request, on a case-by-case basis (similar to the manner in which BSEE currently reviews operators' Safety and Environmental Management System (SEMS) programs), we have not estimated any additional costs to BSEE as a result of this requirement.

[20] Under the Paperwork Reduction Act, we estimated that it will take 5 burden hours to develop each RTM plan. Based on the assumption that industry staff (a mid-level engineer) will develop these plans, at a compensation rate of $89.42 per hour, the one-time cost of this requirement would be about $447 per plan. Over the 10-year economic analysis period, the average annual cost would be about $44.7 per plan. (We believe that the total costs for small entities could be even smaller since, based on the comments submitted by industry, some operators already have RTM plans that may merely need some adjustment to satisfy the final rule requirements; nonetheless, we have estimated here that all affected small entities would need to develop such plans.) These estimated costs are so small that they are effectively subsumed by the overall costs of complying with the RTM requirements generally.

[21] We estimated that the average costs per day and the average operational days per year will be the same for rigs with subsea BOPs, surface BOPs on floating facilities, and rigs operating in HPHT reservoirs. We estimated 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 will be $5,000, including equipment and labor. This estimate is based on the experience of the BSEE regulatory staff, working in conjunction with BSEE engineers who interact with industry on a regular basis and review the equipment. 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) will incur a new cost to comply with these requirements. Similarly, we estimated that a total of 10 rigs (*i.e.*, 5 floating facilities with a surface BOP and 5 rigs in HPHT reservoirs) will incur a new cost to comply with these requirements. We multiplied the number of days per year that the rig is operational 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.

BSEE received several comments suggesting that the costs associated with RTM of well operations were underestimated in the RIA for the proposed rule. These comments tended to assume greater demands on the RTM systems than the proposed rule actually required, such as the exchange of more information through RTM than was necessary under the rule. BSEE has clarified the final rule in response to the comments, including removing or replacing several provisions that were perceived by commenters as overly prescriptive with more flexible, performance-based measures that better reflect BSEE's intention that operators use RTM as a tool to improve their own ability to prevent well control incidents. Consistent with the requirements of the final rule, BSEE maintained its cost estimates of RTM, and did not increase them as suggested by these comments.

k. Additional documentation and verification requirements for BOP systems and system components

Section 250.730 lists general requirements for BOP systems and system components and adds new documentation and verification requirements.[22] We estimated an annual labor cost to industry of about $1,800 associated with these submissions and labor costs to BSEE of about $700.[23] We were unable to estimate the cost for a certification entity to meet the requirements of ISO 17011 for quality management systems for BOP stacks.

[22] Section 250.730(d) requires 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 submits relevant information about the alternative program. Additionally, new paragraph (d) will result in labor costs to industry associated with submitting requests for alternative programs.

[23] We estimated that a mid-level industry engineer will spend 2 hours to submit a request, at a compensation rate of $89.42 per hour, for each of ten wells during the year. We estimated that a mid-level BSEE engineer will spend 1 hour to process a request, at a compensation rate of $67.85 per hour.

Section 250.731(c) requires verification by a BAVO 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 § 250.731(c) regarding certification for BOP systems and system components will 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 will incur this new cost. This calculation resulted in one-time equipment and service costs for this certification requirement of $12.8 million to industry.[24]

Section 250.732(c) requires a comprehensive review by a BAVO of BOP and related equipment for use in high temperature and high pressure conditions. The requirements in new § 250.732(c) surrounding a review of BOP systems and system components in HPHT conditions will result in new annual costs to industry. To calculate the costs associated with the required verifications of BOP systems and components by BAVOs, we estimated the annual cost for performing the verification and multiplied the annual cost by the number of wells that will incur this new cost. This calculation resulted in annual equipment and labor costs for this verification requirement of $500,000 to industry.[25]

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

[24] We estimated that the service costs per well will be $40,000. We estimated that 320 wells will 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.

[25] We estimated that the annual costs per well will be $50,000. We estimated that 10 HPHT wells will 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.

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) requires 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) requires a listing of the functions with sequences and timing of autoshear, deadman, and EDS for subsea BOPs. Paragraph (b) adds 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) requires submission of a certification that a Mechanical Integrity Assessment report has been submitted within the past 12 months. New paragraphs (c) and (d) include a change in required certifications; the paragraphs require submission of certification from a BAVO (rather than a "qualified third party")[26] that:

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

(2) The BOP has been designed, tested, and maintained to perform under the maximum environmental and operational conditions anticipated to occur at the well; and

[26] BSEE expects that BAVOs will come from current qualified third-parties used by operators under BSEE's former regulations and industry standards. In addition, the certifications required under new §§ 250.731(c) and (d) are similar to the verifications required by former §§ 250.416(e) and (f). Thus, we do not expect any incremental costs from these new certification requirements.

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

These 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 has sufficient fluid to function the BOP system without assistance from the charging system.

The requirements to provide additional documentation about the BOP system and system components in the APD, APM, or other submittal will 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 will 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 will 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 about $29,000 to industry and $22,000 to BSEE.[27]

[27] We estimated that industry staff (a mid-level engineer) will 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 ($89.42) and by the average number of wells drilled per year (320) to obtain an average annual labor cost to industry of $28,614. We estimated that BSEE staff (a mid-level engineer) will 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

m. Submission of a Mechanical Integrity Assessment Report

Section 250.732(d) includes new requirements on the submission of a Mechanical Integrity Assessment Report on certain BOP stacks and systems. New paragraph (d) outlines the requirements for this report, which must be completed by a BAVO and submitted by the operator for operations that will 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 § 250.731(f) requires certification stating that this report is submitted to BSEE prior to beginning any operations (to include maintenance and repairs) involving these BOPs. The BAVO report will 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 will 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 will be affected. This calculation resulted in annual capital costs for reporting of $4.8 million to industry. 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 then multiplied this 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 will 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 cost by the number of additional reports expected per

a mid-level BSEE engineer ($67.85) and by the average number of wells drilled per year to obtain an average annual labor cost to BSEE of $21,710.

year. These calculations result in average annual labor costs for this reporting requirement of $44,709 to industry and $10,855 to BSEE. We then summed the labor and reporting costs to industry to obtain an annual cost to industry of about $4,840,000 and annual costs to BSEE of about $11,000.[28]

Similarly, paragraphs 250.732(d) and (e) require the submittal of a Mechanical Integrity Assessment report. We calculated this annual cost by multiplying the time required to complete the task by the number of submittals per year and by the hourly compensation rate of the industry staff most likely to complete the task. These calculations result in an annual labor cost to industry of about $80,000.

BSEE received a comment that included a substantially higher estimate of the cost to operators for submitting the Mechanical Integrity Assessment Report. However, BSEE notes that the commenter incorrectly calculated this cost on a per-well basis, instead of on a per-rig basis, which is how the cost will actually be accrued.

n. <u>New surface BOP requirements</u>

Section 250.735 includes new requirements for surface BOP stacks, and new paragraph (g) requires that locking devices be installed with surface BOPs. BSEE recognizes that the equipment and labor costs associated with the surface BOP stack requirements will be case-specific. In response to industry comments, BSEE estimates that this new requirement will create a new one-time equipment cost to industry for the installation of the hydraulically

[28] We estimated an annual capital cost of $15,000 for each well of 320 wells, which results in an annual capital cost of $4.8 million. For labor costs, we estimated that industry staff (a mid-level engineer) will spend a half hour to prepare a report for each well, at a compensation rate of $89.42. We estimated that BSEE staff (a mid-level engineer) will spend a half-hour to receive and review the report for each well, at a compensation rate of $67.85.

operated locks. We estimated this cost by multiplying the cost per equipment part by the number of rigs with surface BOPs, resulting in a one-time cost to industry of $2.50 million.[29]

BSEE received comments on the costs that were in the initial RIA for the proposed rule, associated with the requirements for surface BOP stacks. Some comments suggested that BSEE had neglected to estimate the cost of requiring the installation of hydraulically operated locks on surface BOP systems under proposed § 250.733. BSEE has deleted that proposed requirement from the final rule, as explained in the preamble to the final rule. In addition, BSEE has revised a similar requirement for surface BOPs in final § 250.735(g) to require remotely-controlled locks (which may or may not be hydraulically operated) on blind shear rams (rather than all sealing rams). Although the requirement in the final rule has been revised in ways that will be less costly, compared to the proposed rule, BSEE agrees that the cost of this requirement was not included in the initial RIA, and therefore added this cost into the final economic analysis. As one of the comments suggested, BSEE has added a one-time cost of $50,000 for each of the estimated 50 surface BOP rigs expected to require this installation.[30]

BSEE also received a comment stating that proposed § 250.733(b)(2) would require dual bore risers for existing BOPs on floating production facilities, which would necessitate the replacement of several existing riser systems. The proposed rule was not intended to have that

[29] Based on industry comments, BSEE has revised the cost estimate for this provision. Since operators may choose to use hydraulically operated locks to comply with this requirement for remotely controlled locks, we have continued to assume the use of hydraulic locks when analyzing the costs of this new requirement, even though that likely results in an overestimation of the cost (since hydraulic locks would typically be more costly to install than alternative remotely-controlled locks). The cost of installing a hydraulically operated lock is estimated at $50,000. We multiplied this cost by the number of rigs with surface BOPs (50) to obtain the one-time cost estimate to industry of $2.5 million.

[30] BSEE does not expect that any additional maintenance or inspection costs will result from the new remotely-controlled lock requirements in §250.735(g), since maintenance and inspection of BOP equipment is already industry practice under former regulations (*e.g.*, § 250.446(a)) and existing industry standards (*i.e.*, API Standard 53). In addition, the new locking requirement will not significantly extend the time for inspections or maintenance since those locking devices are a relatively straightforward and small component of the overall BOP system.

effect, and BSEE has revised the dual bore riser requirements in the final rule to clarify that the requirement will be limited to facilities or BOPs installed after the effective date of the final rule. Current drilling risers will not need to be replaced under this requirement. Thus, BSEE does not anticipate any additional replacement costs for current drilling risers. Similarly, since BSEE has not approved the installation of new single bore risers for at least 8 years, the requirement that risers installed after the effective date of the final rule must be dual bore risers merely confirms past practice and will not result in any new costs.

o. New subsea BOP system requirements

Section 250.734 includes new requirements for subsea BOP systems, based on recommendations from the *Deepwater Horizon* incident investigations. Revised paragraph (a) requires that BOPs be equipped with dual shear rams and outlines the requirements for the shear rams.

BSEE recognizes that the equipment costs associated with these new subsea BOP system requirements will be case-specific. For example, the costs will 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. Since API Standard 53 covers the requirements under paragraph (a) for all rigs with the exception of moored rigs, the costs of these requirements, except the costs associated with moored rigs, are included in the baseline. 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.[31]

Several comments on particular proposed provisions, especially on requirements for subsea BOP systems, suggested that BSEE left out a cost that the commenter associated with the requirements of those particular provisions of the rule. However, BSEE did include these costs under a different section of the proposed rule (*e.g.*, § 250.735(a)) that also related to the same general requirement.

Some comments suggested that BSEE underestimated the cost of the requirement involving the installation of a gas bleed line under § 250.734(a)(15). BSEE revised this requirement in the final rule (by clarifying the location of the gas bleed line), and the final requirement now will impose lower costs than the requirement in the proposed rule. Based on BSEE's current analysis, the vast majority of subsea BOPs already have a gas bleed line installed, and the ones that do not will require only very slight modification under the final rule. Thus, the final RIA estimates a lower cost for the final requirement.

p. <u>New accumulator system requirements</u>

Section 250.735(a) lists new requirements for the accumulator system of a BOP. The accumulator system must operate all BOP functions against maximum anticipated surface pressure (MASP) with at least 200 pounds per square inch remaining on the bottles above the

[31] Although the actual costs for obtaining and installing any new equipment required by this section will vary, as stated above, based on existing technology for centering/shearing and on BSEE's discussion with a relevant equipment manufacturer, BSEE believes that the height of the subsea BOP stacks will not need to change significantly. We also estimated that 5 moored rigs will be affected and, that the one-time capital compliance costs, including installation costs, associated with these shear ram requirements will be $10 million per rig. We thus estimated a total one-time capital cost to industry of $50 million.

pre-charge pressure without use of the charging system. Revised paragraph (a) details additional accumulator requirements regarding fluid capacity and accumulator regulators. This revision will ensure that the BOP system is capable of operating all critical functions.

The requirement that the accumulator system operate all functions for all BOP systems will result in a one-time equipment and labor cost to industry. 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 about $2.4 million.[32] No incremental rig downtime or daily rig costs are expected (since this work can be planned for and done during routine maintenance or downtime scheduled for other reasons), and no additional costs to BSEE are expected, as a result of this requirement.

BSEE received comments on the new accumulator system requirements in the proposed rule, including estimates of industry costs to comply with these requirements. Many of the estimated costs presented in these comments exceeded the costs estimated by BSEE in the initial RIA. The final regulatory text for this requirement has been substantially revised (*e.g.*, to be more

[32] BSEE estimated that the cost of the additional equipment needed to meet the requirements will be $25,000 per rig. It is unknown how many rigs already comply; thus, we made a conservative assumption that all rigs will be affected (90 rigs). We obtained an estimated one-time equipment cost of $2.25 million. For the one-time labor cost to industry, we estimated that three days of industry time will be required per rig to install the new equipment. We estimated that industry staff (a mid-level engineer) will spend 24 hours to install the new equipment on a rig, at a compensation rate of $89.42 per hour. This rendered an estimated one-time labor cost to industry of $193,143. Summing the equipment and labor costs resulted in a total one-time cost to industry of $2,443,143.

consistent with fluid volume capacity in API Standard 53), thereby reducing its cost to industry.[33]

q. Chart recorders

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

This testing requirement will result in a one-time equipment and labor cost to industry for those operators that do not already have the required equipment. Some operators will have to purchase the equipment (a chart recorder or digital 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 estimated total number of rigs that may need it. 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 about $90,000.[34] No additional costs to BSEE are expected as a result of this requirement.

r. Notification and procedures requirements for testing of surface BOP systems

[33] BSEE assumes that operators already meet the accumulator capacity criteria of API Standard 53; thus, all of the costs of compliance with revised final § 250.735(a) could have been included in the economic baseline. However, BSEE has elected to include the cost described above ($2.4 million) in the estimated costs of compliance with the final regulations.

[34] We estimated that a chart recorder would have an average cost of $2,000 per rig, for each of 45 rigs (half of the 90 rigs in total, with the other half estimated to already have the equipment). This yielded an estimated one-time equipment cost to industry of $90,000. We estimated that industry staff (rig crew) will spend five minutes (0.08 hours) per rig to install the equipment at an average hourly compensation rate of $57.20. This resulted in a total one-time cost to industry of $90,215.

Section 250.737(d)(2) expands notification and procedures requirements regarding the use of water to test a surface BOP system on the initial test. These expanded notification and procedural requirements will 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 cost by the total number of annual submittals. These calculations resulted in an annual cost to industry of about $5,400 associated with these submissions. This new requirement will 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 submittals and then multiplied this cost by the total number of annual submittals.[35] These calculations resulted in an annual cost to BSEE of about $4,100.

s. <u>Alternating BOP control station function testing</u>

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

This testing requirement will 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

[35] We estimated that a mid-level industry engineer will spend 1 hour on a submittal as a result of these expanded requirements, at a compensation rate of $89.42 per hour, for each of 60 submittals, for an annual cost to industry of $5,365. We estimated that a mid-level BSEE engineer will spend 1 hour to process a submittal, at a compensation rate of$67.85, for an annual cost to BSEE of $4,071.

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.[36]

t. ROV intervention function testing

Section 250.737(d)(4) establishes requirements for testing ROV intervention functions to include testing and verifying the closure of the selected ram(s).

This testing requirement will 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 about $417,000.[37] No additional costs to BSEE are expected as a result of this requirement.

BSEE received a comment that this section would require the testing of ROV intervention functions, and that these tests would require additional operational time per well, thereby imposing additional costs in terms of operational time. However, the final rule has been revised to be more consistent with API Standard 53 with regard to ROV intervention testing. Therefore,

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[36] We estimated that testing would require 0.5 days per rig per year. Because subsea and surface BOP 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 ($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). 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.

[37] We estimated that it will take five minutes per well to conduct the testing and that 120 wells will be affected (40 subsea BOP rigs with three wells per rig). We considered the time diverted for testing as a fraction of a day (0.003472) and the daily operating cost per rig ($1,000,000) to obtain an average annual operations cost to industry of $416,667.

BSEE does not estimate that there will be any additional costs to operators in this regard since such testing is within industry standards (*e.g.*, API Standard 53) and is thus within the baseline of the analysis.

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

Section 250.737(d)(12) expands the requirements for function testing of autoshear, deadman, and EDSs on subsea BOPs. It requires 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 is 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 throughout the test. It requires that the blind-shear rams be tested to verify closure. The operator must document the plan to verify closure of the casing shear ram(s), if installed, as well as all test results.

These documentation and testing requirements will result in a one-time equipment cost and increased annual operating costs to industry. The industry will 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 will 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 documentation 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.[38] No additional costs to BSEE are expected as a result of this requirement.

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

Section 250.738 describes the required actions for specified situations involving BOP equipment or systems. Paragraphs (b), (i), and (o) include requirements for reports from BAVOs. Reports previously required to be prepared by a "qualified third party" under these sections will be required to be prepared by a BAVO. Paragraph (m) includes a similar change and introduces a requirement that an operator request approval from the BSEE District Manager if the operator plans to use well control equipment not covered in Subpart G. The operator must submit a report from a BAVO, as well as any other information required by the District Manager. This new approval request requirement will result in annual labor costs to industry and BSEE of about $13,000 and $10,000, respectively.[39]

w. Breakdown and inspection of BOP system and components

Section 250.739(b) introduces a requirement for a complete breakdown and inspection of the BOP and every associated component every 5 years, which may be performed in phased

[38] We estimated that the average cost of the sensing device will 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. We estimated that it will 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 estimated that all subsea BOP rigs (40) will 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.

[39] These estimates are based on the assumption that industry staff (a mid-level engineer) will spend an average of 0.81 hours per report, at a compensation rate of $89.42 per hour, for approximately 183 reports per year. It was estimated that BSEE staff (a mid-level engineer) will spend the same amount of time to review and process the report, at a compensation rate of $67.85 per hour.

intervals. During this complete breakdown and inspection, a BAVO must document the inspection and any problems encountered. This BAVO report must be available to BSEE upon request. This additional requirement is necessary to ensure that the components on the BOP stack will 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 inspection and documentation requirement will result in costs to industry associated with generating reports by BAVOs. To calculate this report cost, we multiplied the estimated report cost per rig 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 of the costs for subsea and surface BOP rigs. Assuming staggered inspections, we estimated that, in each year, an average of eight subsea BOP rigs would undergo inspections, thereby enabling all 40 subsea BOP rigs to undergo such inspections over a five-year period. Similarly, we estimated that 10, of a total of 50, surface BOP rigs would undergo inspections each year. This resulted in annual costs to industry of $4.3 million.[40]

The proposed rule contained a requirement that operators breakdown the entire BOP system every five years for recertification, without the option to phase or stagger recertification. BSEE received comments that this requirement would cause rigs to be out of service for extended periods of time, at substantial opportunity costs to industry. BSEE revised the requirement in the final rule to allow for staggered inspections over the course of five years. This change eliminates

[40] For subsea BOP rigs, we estimated that equipment and labor cost will be $350,000 per rig, for each of 8 subsea BOP rigs each year, resulting in an annual cost of $2.8 million. For surface BOP rigs, we estimated that equipment and labor cost will be $150,000 per rig, for each of 10 rigs per year, resulting in an annual cost of $1.5 million.

the need for rigs to be brought out of service for extended periods of time, and significantly reduces costs associated with this new requirement.

x. Additional recordkeeping for RTM

Sections 250.740(a) and 250.741(b) introduce requirements for recordkeeping of RTM data and other well operation data. This additional record-keeping will 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 about $1,500 to industry.[41] No additional costs to BSEE are expected as a result of these requirements.

y. Industry familiarization with the new rule

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

Reviewing the new regulations will 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

[41] We estimated that industry staff (administrative staff) will spend 0.5 hours per well to keep RTM records. We multiplied the number of industry staff hours per well by the average hourly compensation rate for administrative staff ($24.31), 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 $1,459 or about $ 12 per entity per year.

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 about $20,000.[42]

z. BAVO application costs

Qualified third-parties currently perform verifications, under BSEE's former rules and current industry practice, that are similar to the certifications and verifications that a BAVO will be required to perform under § 250.732(a) of the final rule. BSEE expects that many of these existing third-party organizations will become BAVOs. To become a BAVO, organizations will need to apply to BSEE and have their applications approved by BSEE. Those that are approved as BAVOs will then be placed on a list for operators to use in finding a BAVO that will enable the operators to obtain the required certifications and verifications.

We estimated the number of BAVO applications to be 15 in the first year (2016), three in the second year (2017), and two per year for each of the remaining eight years (2018 to 2025). We further estimated that organizations would require, on average, about 100 hours of a mid-level engineer's time to complete and submit each application. We also estimated that BSEE would require, on average, about 40 hours of a mid-level engineer's time to review and process each application, except during the first year, in which BSEE would require 80 hours per application (since BSEE will need additional time in the first year to develop and begin implementing the

[42] We estimated that industry staff (a professional engineer, supervisory) will spend two hours to review the new regulation. We estimated the average hourly wage rate for a professional engineer (supervisory) as $53.00. We multiplied this wage rate by the private sector loaded wage factor of 1.43 to account for employee benefits, resulting in a loaded average hourly compensation rate of $75.79. We estimated that an industry staff person will 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 $19,705 to industry.

approval process). These estimates result in average annual costs to industry of about $30,000 per year, and to BSEE of about $13,000 per year, for a total average annual cost of $44,000.[43]

6. Summary of the cost analysis

Exhibit 1 summarizes the estimated cost for the rule by provision.

[43] The total average annual cost reflects rounding; using a compensation rate of $89.42 per hour for industry produced an average annual cost to industry of $30,403, and using a compensation rate of $67.85 for BSEE produced an average annual cost to BSEE of $13,299.

EXHIBIT 1: COST OF THE RULE BY PROVISION (Thousands of 2014$)[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	$286	$29	0.03%	100.00%	0.00%
(b) Additional information in the drilling prognosis	$72	$7	0.01%	100.00%	0.00%
(c) Prohibition of a liner as conductor casing	$7,950	$795	0.89%	100.00%	0.00%
(d) Additional capping stack testing requirements	$2,262	$226	0.25%	100.00%	0.00%
(e) Additional information in the APM for installed packers	$102	$10	0.01%	56.86%	43.14%
(f) Additional information in the APM for pulled and reinstalled packers	$397	$40	0.04%	56.86%	43.14%
(g) Rig movement reporting	$71	$7	0.01%	56.86%	43.14%
(h) and (i) Information on MODUs	$3,664	$366	0.41%	56.86%	43.14%
(j) Real-time monitoring of well operations	$405,000	$40,500	45.49%	100.00%	0.00%
(k) Additional documentation and certification requirements for BOP systems and system components	$17,825	$1,782	2.00%	100.00%	0.00%
(l) Additional information in the APD, APM, or other submittal for BOP systems and system components	$503	$50	0.06%	56.86%	43.14%
(m) Submission of a Mechanical Integrity Assessment Report by a BSEE approved certification organization	$49,079	$4,908	5.51%	100.00%	0.00%
(n) New surface BOP requirements	$2,500	$250	0.28%	100.00%	0.00%
(o) New subsea BOP system requirements	$50,000	$5,000	5.62%	100.00%	0.00%
(p) New accumulator system requirements	$2,443	$244	0.27%	100.00%	0.00%
(q) Chart recorders	$90	$9	0.01%	100.00%	0.00%
(r) Use water to test surface BOP system on the initial test	$94	$9	0.01%	56.86%	43.14%
(s) Alternating BOP control station function testing	$250,000	$25,000	28.08%	100.00%	0.00%
(t) ROV intervention function testing	$4,167	$417	0.47%	100.00%	0.00%
(u) Autoshear, deadman, and EDS system function testing on subsea BOPs	$50,100	$5,010	5.63%	100.00%	0.00%
(v) Approval for well control equipment not covered in Subpart G	$233	$23	0.03%	56.86%	43.14%

EXHIBIT 1: COST OF THE RULE BY PROVISION (Thousands of 2014$)[1]					
	Total 10 Year Cost (undiscounted)	**Average Annual Cost (undiscounted)**	**Percent of Total Cost**	**Industry Share**	**Government Share**
(w) Breakdown and inspection of BOP system and components	$43,000	$4,300	4.83%	100.00%	0.00%
(x) Additional record-keeping for real-time monitoring	$15	$1	0.00%	100.00%	0.00%
(y) Industry familiarization with the new rule	$20	$2	0.00%	100.00%	0.00%
(z) BAVO applications	$437	$44	0.05%	69.57%	30.43%
TOTAL	$890,309	$89,031	100.00%	99.74%	0.26%

[1] Totals may not add because of rounding.
[2] This is a lower-bound estimate of the costs of this provision; BSEE was not able to estimate some of the costs (see section 5 above for details).

7. Discussion of Indirect Impacts of the Rule

Some of the comments received during the public comment period suggested that BSEE should consider broader or indirect economic impacts that may occur as a result of the rule. One of these comments also provided an economic analysis of the asserted broad effects of the rule on the national economy.

BSEE does not agree that what the commenters described as “indirect costs” of the rule are within the scope of the RIA as required by E.O. 12866. OMB Circular A-4 characterizes the indirect effects of a rulemaking as “ancillary benefits and countervailing risks,” but also states that these types of forecasted consequences, if highly speculative, may not be worth further formal analysis. Because there are a number of important and variable factors (unrelated to the implementation of the new regulations), such as the future price of oil, that will impact both the offshore oil and gas labor market and the marketplace for offshore oil and gas equipment and products, BSEE believes it is too speculative to predict whether this rulemaking will have the types of broad and indirect effects discussed by the comments. In addition, the indirect impacts expressed by the comments appear to be overstated or based upon certain assumptions for which there is no clear foundation.[44] Moreover, many of those estimated costs appear to be associated with requirements that are part of the economic baseline (*e.g.*, compliance with relevant provisions of API Standard 53), while others are associated with requirements discussed in the proposed rule that are not included in the final rule (*e.g.*, the proposed 1.5 times volume capacity accumulator requirement).

In addition, the commenters did not take into account the potential private benefits to industry in terms of reduced costs of operation associated with implementation of the new regulations. In particular, the reduction in costs attributable to the change in the BOP pressure testing frequency for workovers and decommissioning is expected to exceed the costs that will result from the final rule.

Several commenters asserted that BSEE did not adequately account for the additional costs to contractors that would result from the rule. BSEE disagrees with this comment because, in estimating costs, BSEE considered the costs of all of the equipment and labor services that would be needed to meet new requirements, regardless of how that equipment or labor is provided (whether by lessees or by contractors). Moreover, if the labor or equipment is provided by contractors, their cost must be incurred by operators who would reimburse their contractors for their expenses.

Commenters also stated that the RIA should have addressed negative impacts to industries that support offshore oil and gas exploration and development. BSEE disagrees with this comment. The economic analysis included in the initial RIA considered the costs of all of the

[44] For example, one comment assumed that the costs of the rule would lead to a 20 percent decrease in the number of floating units and over 30 percent decrease in fixed platforms, but provided no explanation for those assumptions.

equipment and labor services that would be needed to meet the new requirements. Moreover, many of the negative impacts projected by the commenters are speculative and outside the scope of the type of analysis required to support this rulemaking. In addition, some commenters projected additional costs to industries that support offshore oil and gas exploration and development, but did not address whether there are potential benefits to other types of industries resulting from the new requirements. Thus, even assuming they were within the scope of this analysis, these comments did not present a complete picture of the potential impacts on other industries.

BSEE received comments suggesting that the analysis did not account for the impacts of the regulation on national energy security. These comments suggested that, based on the commenters' cost estimates, the proposed rule would weaken national energy security by reducing domestic oil production and increasing reliance on foreign oil. BSEE does not agree with these comments. The commenters' predictions about the weakening of national energy security is highly speculative and thus outside of the scope of the regulatory impact analysis required by E.O. 12866 and OMB Circular A-4. Rather, future technological advancements and variable market factors (*e.g.*, the price of oil) unrelated to the requirements of this final rule are more likely to affect future domestic oil production than this rule. In any case, given that the final rule will result in net savings to industry, rather than net costs, there is no reason to expect the rule to have any adverse effect on oil supply or any adverse effect on energy security.

8. <u>Benefits Analysis</u>

We have quantified three types of benefits that will result from the rule: time savings, potential reductions in oil spills, and potential reductions in fatalities (*see* Sensitivity Analysis, section 10.b, below). For example, a time-savings benefit will result from § 250.737(d)(10), which will streamline blind-shear ram(s) function testing, and reduce the time required for this testing, by making the testing interval the same as the interval for BOP pressure testing (*i.e.*, 14 days).

a. Private Benefits: <u>Time Savings from Revised BOP Pressure Testing Frequency</u>

BSEE is changing the BOP pressure testing frequency for workover and decommissioning operations to once every 14 days, which is consistent with the longstanding testing frequency for drilling and completion operations under the existing rules. 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 is harmonizing the requirements for that type of equipment. Harmonization of the pressure testing frequency for all operations will also streamline the BOP function-testing criteria. In addition, based on BSEE's experience with the longstanding 14-day testing interval for BOPs used in drilling and completions, the testing of BOPs used in decommissioning and workovers every 14 days will avoid the extra wear and tear and safety risks inherent in 7-day testing and will not result in any diminution of safety and environmental protection as compared to 7-day testing.

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. We estimated that this requirement will save three days of operating time per rig each year. BSEE estimates that the pressure testing takes about 20 hours and that the trip time is about 52 hours for workover and decommissioning operations. We estimated that the daily operating cost is $1 million for each of the 40 subsea BOP rigs, and

$200,000 for each of the 50 surface BOP rigs, resulting in an estimated annual time savings to industry of $150 million.[45]

BSEE also estimated the additional potential time-savings benefit that could have resulted under Alternative 2 (*i.e.*, reducing pressure testing frequency for all BOPs to once every 21 days), and thus further decreasing the number of required tests per year for operators. To estimate the potential time-savings benefit associated with Alternative 2, we made the following assumptions:

- We estimated that operators would conduct 26 pressure tests per year (*i.e.*, one test every 14 days) for all four types of operations (as specified in Alternative 1). BSEE recognizes that operators will not likely operate continuously, but we estimated continuous operations as a conservative approach because this approach results in the highest number of tests estimated to be conducted per year and thus the largest estimated costs per year.
- We estimated that, under Alternative 2, 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 under Alternative 2.
- We estimated that each BOP pressure test takes 20 hours, based on input from subject matter experts contacted by BSEE.

We estimated that each rig would 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. Based on

[45] The estimated savings of 3 days (per year), for each of 40 subsea BOP rigs, whose operating cost is $1 million per day, is $120 million. The estimated 3-day savings for 50 surface BOP rigs, whose operating cost is $200,000, is $30 million. Thus, the net cost savings is $150 million per year.

these estimated daily rig operating costs, we estimated an annual per-rig benefit of $7.5 million for subsea BOP rigs and $1.5 million for surface BOP rigs. Accounting for the number of rigs estimated to be operating on the OCS, we estimated an annual time-savings benefit of $300 million for subsea rigs and $75 million for surface rigs.[46] As a result, the total benefits under Alternative 2 (including the benefits of extending the BOP pressure testing interval for workovers and decommissioning from 7 to 14 days) would be approximately $525,000,000 annually (*see* Exhibit 3 for further details of these benefits).

BSEE did not include in this analysis the additional cost-savings benefit of reduced trip time in the calculations of potential time-savings for Alternative 2.[47] 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.

[46] 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.

[47] 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.

As discussed earlier in this analysis, after reviewing public comments on this issue, BSEE did not select Alternative 2 because BSEE lacks critical data on testing frequency and equipment reliability to justify such a change at this time. BSEE expressly invited comments on this alternative in the proposed rule and, given the potential costs savings ($400 million dollars per year) that the initial RIA estimated could have resulted from extending all pressure testing to 21-day intervals, BSEE anticipated that significant technical and economic comments on this issue would be submitted. Comments in support of such a change were submitted; however, these comments did not provide adequate data and information to support adopting a 21-day testing interval. Although BSEE is aware of concerns that the more frequently BOPs are tested, the more likely the equipment is to wear out prematurely, it does not follow that every extension of test intervals always increases reliability, and thus safety and environmental protection, in the long-term. In the absence of new data demonstrating that 21-day testing would be as protective as 14-day testing, BSEE has decided that it is not prudent or appropriate to adopt 21-day testing in the final rule. In response to the *Deepwater Horizon* incident, industry attempted to voluntarily improve the overall reliability of well control equipment through better designs, improved manufacturing processes, better maintenance and repair procedures, and increased data sharing. BSEE will consider the possibility of adopting 21-day BOP testing when it receives adequate new (post-*Deepwater Horizon*) data and analyses demonstrating that BOP reliability and capability, and personnel safety, are not adversely affected (or are actually improved) by pressure testing at 21-day intervals. This could include, for example, data from BOP testing and usage in OCS or other waters. BSEE will consider relevant data, along with any data indicating that the other requirements contained in this rule (such as BAVO verification), have increased overall BOP performance and reliability and decreased the risk of failure of the systems and components.

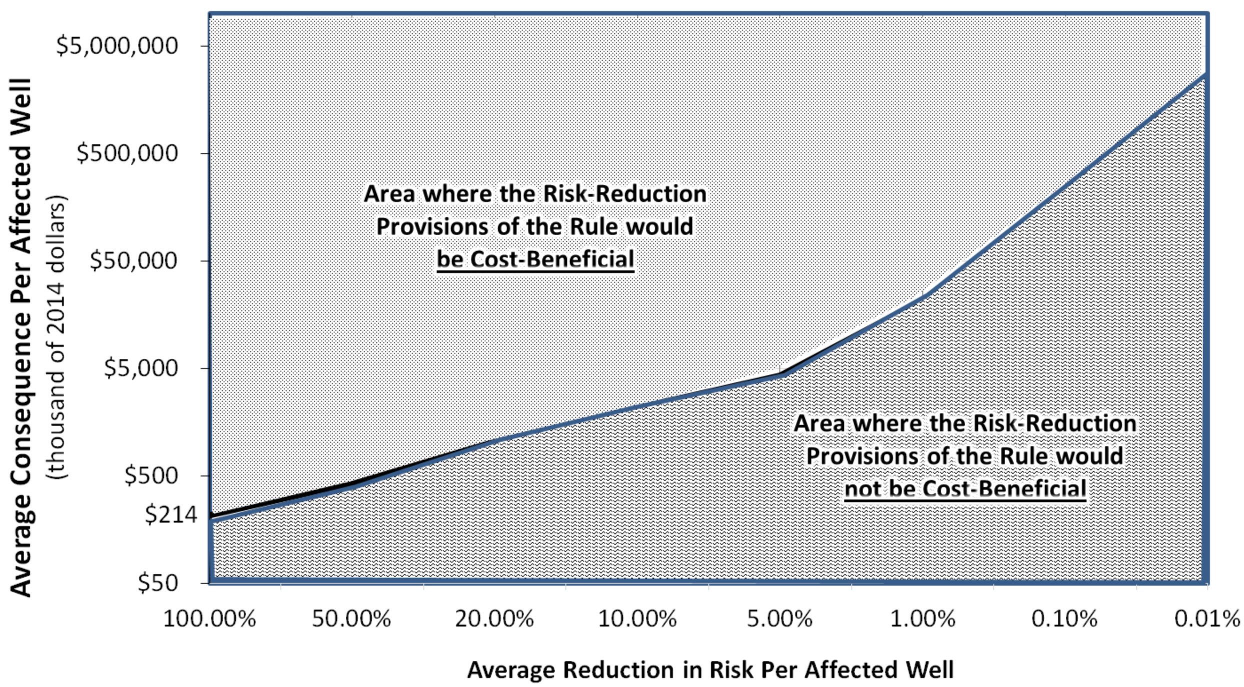
b. Social Benefits: <u>Potential reductions in oil spills</u>

In addition to the cost savings from the revised requirement for pressure testing of certain BOPs, the final rule will 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 rule in reducing the number of incidents as well as the magnitude of the incidents, which is highly uncertain.

In order for the regulatory provisions of the rule to be cost-beneficial solely from a risk reduction perspective (*i.e.*, without the cost savings from changing the pressure testing interval for workover and decommissioning BOPs), the rule would need to achieve at least $686 million (discounted by 7 percent over 10 years) in risk reduction benefits. Taking into account the uncertain monetized and qualitative benefits from reducing the risks of oil spills, as well as the potential range of risk reduction levels attributable to the rule, we have performed a sensitivity analysis summarizing the potential benefits from reducing the risks of oil spills (as well as fatalities) at risk reduction levels of 0 to 20 percent. *See* part 10 and Exhibit 5 below.

Another method for exploring whether a rule could be cost-beneficial on the basis of risk reduction is through a break-even analysis. One way to present such an approach is to illustrate the different levels of the potential levels of risk reduction vs. the potential consequence reduction benefits of the rule (*e.g.*, on a per well basis) that would be needed to exceed the cost. Figure 1 is an illustration of different levels of risk and consequence reductions holding cost constant. Although Figure 1 is based on the total 10-year discounted cost of the rule ($686 million) - excluding the cost savings from the final BOP pressure testing frequency provision - and the estimated total number of new wells (3,200) drilled over the 10-year period, the graph is for illustrative purposes only; it does not predict the level of benefits that will be achieved at any particular level of risk reduction.

Figure 1 – Break-Even Illustration



The types of risk reduction benefits that are expected from this rule include reduced costs of injuries and fatalities, oil spill cleanup, damages to facilities and equipment, and lost tourism from an oil spill. Potential benefits also include the value to society of protecting the environment (*e.g.*, protection of animal species, preservation of the oceanic ecosystem) by reducing the risk and consequences of oil spills. While these collective benefits are difficult to quantify, the *Deepwater Horizon* disaster provides a recent, real-world example of the scope of the potential costs to be avoided, currently in excess of $40 billion and growing, and thus of the potential benefits to be gained by reducing the risks of major oil spills. In addition, the final rule is expected to reduce the risks of smaller-scale, and more frequent, losses of well-control and oil spill events. For further discussion of net risk reduction benefits, see the Sensitivity Analysis in part 10 below.

In addition to the time savings and risk reduction benefits presented above, the rule 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 "Economic Analysis Methodology for the Five Year OCS Oil and Gas Leasing Program for 2012-2017" (the "BOEM Case Study").[48]

i. Benefits Data

To estimate the potential benefits of the rule associated with reducing the risk of oil spill 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.

[48] 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.

Based upon an analysis of the BSEE oil spill database during the period 1988 to 2010, BSEE identified LWCs associated with oil spills greater than 10 barrels and used this data within the economic analysis.[49] BSEE used 1988 as the starting year of the analysis because DOI undertook a comprehensive overhaul of its offshore regulatory program in that year, which thus provides the most relevant context for evaluating the current state of risk that now exists in OCS operations. The LWCs 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.[50] Accordingly, the potential risk reduction benefits associated with this rule are likely understated.

Exhibit 2 presents the analysis of the spill data, which results in an average rate of oil spilled per drilled well, in the year the well was drilled, of 222.39 barrels. This rate was then used to estimate the level of risk associated with the drilling of new wells in the ten-year period 2016-2025.

Exhibit 2: Analysis of Spilled Barrels of Oil Per Year

Year Drilling Started	Barrels of Oil Spilled	Wells	Spilled Barrels Per Started Well
1988	0	1,118	0
1989	0	1,076	0
1990	0	1,180	0
1991	0	848	0
1992	100	611	0.16
1993	0	1,030	0
1994	0	1,150	0
1995	0	1,190	0

[49] Source: http://www.bsee.gov/Inspection-and-Enforcement/Accidents-and-Incidents/Spills/.
[50] Previous Minerals Management Service (MMS) data indicate that there were a total of 154 LWCs during well operations on the OCS between 1988 and 2015. These LWCs resulted in 14 fatalities, 55 injuries, damage to facilities and equipment, and the release of hydrocarbons.

1996	0	1,291	0
1997	0	1,500	0
1998	0	1,164	0
1999	125	1,051	0.12
2000	774	1,398	0.55
2001	0	1,286	0
2002	350	979	0.36
2003	10	916	0.01
2004	11	932	0.01
2005	0	844	0
2006	35	793	0.04
2007	1,061	633	1.68
2008	0	574	0
2009	262	340	0.77
2010	**4,928,100**	**268**	**18,388.43**
	TOTAL	**TOTAL**	**Weighted Average**
	4,930,828	**22,172**	**222.39**

Source: BSEE Master TIMS Query (March 2016)

ii. Methods

We reviewed the causes of risk without the rule and how those causes of risk would be affected by the rule. In order not to overstate the potential risk reduction, we assumed a 1 percent risk reduction in the likelihood of all oil spills.[51] We present a sensitivity analysis on the assumed risk reduction level in section 9.a below. We estimated that 320 new wells will be drilled in each year, leading to an estimate of 71,165 spilled barrels per year (based on the

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

estimated 222.39 spilled barrels per well). Under the conservative assumption of a 1-percent reduction in spilled barrels per year, we then estimated that the final rule would result in approximately 712 fewer barrels spilled per year.

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 costs of a spilled barrel of oil, which is estimated at $3,658 (in 2014 dollars). We derived this estimate from the BOEM Case Study (cited above), and this estimate includes costs associated with natural resource damages, the value of lost hydrocarbons, and spill cleanup and containment.[52] 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 spilled oil, per the directive of OMB Circular A-4 to include costs regardless of where, when, or to whom the costs accrue.[53] We estimated a natural resource damage cost of $662 per barrel and a cleanup and containment cost of $2,946 per barrel as estimated for the Gulf of Mexico in the BOEM Case Study (both values adjusted to 2014 dollars). We assumed a value of lost hydrocarbon per barrel of $50.

[52] 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.

[53] 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.

We also accounted for one-time costs associated with catastrophic oil spills.[54] Consistent with the BOEM Case Study, we assumed losses associated with recreation of $205 million per catastrophic incident and losses for commercial fishing of $13 million per incident (both values in 2014 dollars). The BOEM Case Study estimated these costs on a per-incident basis.[55] 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 $4,656,376 (($218,594,702 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 $46,564.

The annual benefit from the reduction in spilled barrels of oil and the adjusted one-time costs of a catastrophic event is estimated at $2.6 million (in 2014 dollars), based on the estimated reduction of 712 barrels spilled per year (assuming a 1-percent reduction in spilled barrels) with resulting costs of about $3,700 per barrel.

9. Analytical Findings

Exhibit 3 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 rule is $890.3 million, with $888.0 million of the total cost falling on industry and $2.3 million on

[54] 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.
[55] 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).

BSEE. The discounted total costs for the 10-year period are $790.5 and $686.0 million at 3 and 7 percent discounting, respectively.

EXHIBIT 3: SUMMARY OF MONETIZED COSTS (2014$)[1]				
Year		**Industry Costs**	**Government Costs**	**Total Costs**
			(Thousands of 2014 dollars/year)	
1	**2016**	**$150,049**	**$311**	**$150,361**
2 - 10	**2017 - 2025**	**$81,981**	**$236**	**$82,217**
Undiscounted 10-year total		**$887,876**	**$2,433**	**$890,309**
10-Year Total with 3% discounting		**$788,361**	**$2,148**	**$790,509**
10-Year Total with 7% discounting		**$684,175**	**$1,848**	**$686,023**
10-year Average		**$88,788**	**$243**	**$89,031**
Annualized with 3% discounting		**$92,420**	**$252**	**$92,672**
Annualized with 7% discounting		**$97,411**	**$263**	**$97,674**

[1] Totals may not add because of rounding.

Exhibit 4 displays the monetized benefits for both time savings (under Section 250.737(d)(10) and under § 250.447(b) for Alternative 2) and the assumed 1 percent risk reduction of oil spills for each year and for the 10-year analysis period. The 10-year total benefits for Alternative 1, of the rule, are $1,341 million and $1,147 million at 3 and 7 percent discounting, respectively, with the majority of the *quantified* benefits under Alternative 1 stemming from time-savings benefits under § 250.737(d)(10). The discounted 10-year benefits for Alternative 2 (which would reduce the required frequency of BOP pressure testing to once every 21 days for all operations) are $4,636 million and $3,965 million at 3 and 7 percent discounting, respectively, with the majority of *quantified* benefits under Alternative 2 stemming from time-savings benefits under § 250.477(b).

EXHIBIT 4: SUMMARY OF MONETIZED BENEFITS (AT A 1-PERCENT RISK REDUCTION FROM THE RULE) (2014$)[1]							
	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)**
				(millions of 2014 dollars)			
Each Year 2016 - 2025	$120	$30	$300	$75	$3	$153	$528
Undiscounted 10-year total	$1,200	$300	$3,000	$750	$26	$1,526	$5,276
10-Year Total with 3% discounting	$1,054	$264	$2,636	$659	$23	$1,341	$4,636
10-Year Total with 7% discounting	$902	$225	$2,255	$564	$20	$1,147	$3,965
10-year Average	$120	$30	$300	$75	$3	$153	$528
Annualized with 3% discounting	$124	$31	$309	$77	$3	$157	$543
Annualized with 7% discounting	$128	$32	$321	$80	$3	$163	$565

[1] Totals may not add because of rounding.
[2] Amounts include timesaving benefits of pressure testing and trip time associated with increasing BOP pressure 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 5 summarizes the net benefits at a 1 percent risk reduction. The total 10-year net benefits for Alternative 1 are $551 million and $461 million at 3 and 7 percent discounting, respectively. The 10-year net benefits for Alternative 2 (which would reduce the required frequency of BOP pressure testing to once every 21 days for all operations) are $3,845 million and $3,279 million at 3 and 7 percent discounting, respectively.

EXHIBIT 5: SUMMARY OF NET BENEFITS (AT A 1-PERCENT RISK REDUCTION FROM THE Rule) (2014$)[1]						
	Year	**Total Benefits (Alternative 1)**	**Total Benefits (Alternative 2)**	**Total Costs**	**Net Benefits (Alternative 1)**	**Net Benefits (Alternative 2)**
				(millions of 2014 dollars)		
1	**2016**	$153	$528	$150	$2	$377
2-10	**2017-2025**	$153	$528	$82	$70	$445
Undiscounted 10-year total		**$1,526**	**$5,276**	**$890**	**$636**	**$4,386**
10-Year Total with 3% discounting		**$1,341**	**$4,636**	**$791**	**$551**	**$3,845**
10-Year Total with 7% discounting		**$1,147**	**$3,965**	**$686**	**$461**	**$3,279**
10-year Average		**$153**	**$528**	**$89**	**$64**	**$439**
Annualized with 3% discounting		**$157**	**$543**	**$93**	**$65**	**$451**
Annualized with 7% discounting		**$163**	**$565**	**$98**	**$66**	**$467**

[1] Totals may not add because of rounding.

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

10. Sensitivity Analysis

This section presents sensitivity analyses of the potential benefits of the rule that can be expected to result from varying the following factors:

The level of risk reduction of oil spills achieved by the rule

The level of risk reduction of fatalities achieved by the rule

These sensitivity analyses are presented for Alternative 1, *i.e*, the final 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 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 rule would differ under other assumed levels of reduction in the risk of oil spills. Exhibit 6 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 6 shows how net benefits increase with increased reductions in risk. For example, 10-year total net benefits are $461 million and $551 million at a 1 percent risk reduction and $840 million and $993 million at a 20 percent risk reduction, at 7 and 3 percent discounting, respectively.

EXHIBIT 6: SUMMARY OF NET BENEFITS UNDER DIFFERENT RISK REDUCTION LEVELS (Millions of 2014$)

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	$1,127	$1,318	$610	$441	$527
1%	$3	$20	$23	$1,147	$1,341	$636	$461	$551
2%	$5	$40	$47	$1,167	$1,364	$663	$481	$574
3%	$8	$60	$70	$1,187	$1,388	$689	$501	$597
4%	$11	$80	$93	$1,207	$1,411	$716	$521	$621
5%	$13	$100	$116	$1,227	$1,434	$742	$541	$644
6%	$16	$119	$140	$1,247	$1,458	$769	$561	$667
7%	$19	$139	$163	$1,267	$1,481	$795	$581	$690
8%	$21	$159	$186	$1,287	$1,504	$822	$601	$714
9%	$24	$179	$210	$1,307	$1,527	$848	$620	$737
10%	$26	$199	$233	$1,326	$1,551	$875	$640	$760
11%	$29	$219	$256	$1,346	$1,574	$901	$660	$783
12%	$32	$239	$279	$1,366	$1,597	$928	$680	$807
13%	$34	$259	$303	$1,386	$1,621	$954	$700	$830
14%	$37	$279	$326	$1,406	$1,644	$981	$720	$853
15%	$40	$299	$349	$1,426	$1,667	$1,007	$740	$877
16%	$42	$319	$372	$1,446	$1,690	$1,034	$760	$900
17%	$45	$339	$396	$1,466	$1,714	$1,060	$780	$923
18%	$48	$358	$419	$1,486	$1,737	$1,087	$800	$946
19%	$50	$378	$442	$1,506	$1,760	$1,113	$820	$970
20%	$53	$398	$466	$1,526	$1,784	$1,140	$840	$993

b. Reduction in the Risk of Fatalities

In addition to the time savings and the prevention of oil spills, the rule is anticipated to reduce the risk of fatalities for rig workers. The oil and gas extraction industry makes up a relatively small percentage of the national workforce, but has a fatality rate higher than most industries. The fatality rate for oil and gas extraction workers is 23.9 fatalities per 100,000 full-time equivalent workers (Exhibit 7).

EXHIBIT 7: 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 of $7.9 million (in 2008 dollars), updated to the base year of the analysis, in all benefits analyses that seek to quantify mortality risk reduction regardless of the age, income, or other characteristics of the affected population. This approach was endorsed by EPA in its 2014 Revised Guidelines for Preparing Economic Analyses, found on its website at: http://yosemite.epa.gov/ee/epa/eerm.nsf/vwAN/EE-0568-50.pdf/$file/EE-0568-50.pdf, pages 7-8. 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,[56] inflation, and time lags in the occurrence of adverse health effects.

For the purpose this analysis, BSEE used a VSL of $8.7 million to estimate the avoided costs associated with a reduction in the fatality rate. This is the EPA-recommended estimate of $7.9 million updated to 2014 dollars.

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

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 of oil 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 LWCs resulting in oil 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 $8,685,329, the average cost of fatalities is $2,779,305 per year (0.320 x $8,685,329). Therefore, each 1 percent reduction in the risk of a fatality results in a risk reduction benefit of $27,793 (1% x $2,779,305).[57] Exhibit 8 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 9 presents the effect on the net benefits of the 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 net benefits are $563 million and $471 million at 3 and 7 percent discounting, respectively. Assuming a higher fatality risk reduction of 20 percent, 10-

[57] Note that this calculation likely understates the benefits associated with fatality risk reduction because LWCs 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 LWCs between 1971 and 2006 resulting in 26 fatalities. Accounting for any additional fatalities would increase the fatality risk reduction benefits.

year total net benefits are $567 million and $475 million (at 3 and 7 percent discounting, respectively).

EXHIBIT 8: SUMMARY OF MONETIZED BENEFITS FROM AVERTED FATALITIES

Fatality Risk Reduction	Fatalities Averted	Annual Value (Thousands of 2014 Dollars)	10-year Total (Thousands of 2014 Dollars)		
			Undiscounted	3% Discounting	7% Discounting
0%	0.000	$0	$0	$0	$0
1%	0.003	$28	$278	$244	$209
2%	0.006	$56	$555	$488	$417
3%	0.010	$83	$833	$731	$626
4%	0.013	$111	$1,110	$975	$834
5%	0.016	$139	$1,388	$1,219	$1,043
6%	0.019	$167	$1,665	$1,463	$1,251
7%	0.022	$194	$1,943	$1,707	$1,460
8%	0.026	$222	$2,220	$1,951	$1,668
9%	0.029	$250	$2,498	$2,194	$1,877
10%	0.032	$278	$2,775	$2,438	$2,086
11%	0.035	$305	$3,053	$2,682	$2,294
12%	0.038	$333	$3,330	$2,926	$2,503
13%	0.042	$361	$3,608	$3,170	$2,711
14%	0.045	$389	$3,885	$3,414	$2,920
15%	0.048	$416	$4,163	$3,657	$3,128
16%	0.051	$444	$4,440	$3,901	$3,337
17%	0.054	$472	$4,718	$4,145	$3,545
18%	0.058	$500	$4,995	$4,389	$3,754
19%	0.061	$527	$5,273	$4,633	$3,963
20%	0.064	$555	$5,550	$4,877	$4,171

EXHIBIT 9: SUMMARY OF MONETIZED BENEFITS FROM AVERTED FATALITIES w/ NET BENEFITS (Millions of 2014 Dollars)					
Fatality Risk Reduction	Fatality Risk Reduction Benefit (Total 10-year)	Net Benefits of Rule Without Fatality Risk Reduction (at a 1-Percent Risk Reduction from the Rule) (Total 10-year)	Net Benefits of Rule With Fatality Risk Reduction (at a 1-Percent Risk Reduction from the Rule) (Total 10-year)		
	Undiscounted	Undiscounted	Undiscounted	3% Discounting	7% Discounting
0%	$0.000	$636	$636	$551	$461
1%	$0.278	$636	$636	$551	$461
2%	$0.555	$636	$637	$551	$462
3%	$0.833	$636	$637	$551	$462
4%	$1.110	$636	$637	$552	$462
5%	$1.388	$636	$638	$552	$462
6%	$1.665	$636	$638	$552	$462
7%	$1.943	$636	$638	$552	$463
8%	$2.220	$636	$638	$553	$463
9%	$2.498	$636	$639	$553	$463
10%	$2.775	$636	$639	$553	$463
11%	$3.053	$636	$639	$553	$463
12%	$3.330	$636	$640	$554	$464
13%	$3.608	$636	$640	$554	$464
14%	$3.885	$636	$640	$554	$464
15%	$4.163	$636	$640	$554	$464
16%	$4.440	$636	$641	$555	$465
17%	$4.718	$636	$641	$555	$465
18%	$4.995	$636	$641	$555	$465
19%	$5.273	$636	$641	$555	$465
20%	$5.550	$636	$642	$556	$465

11. Probabilistic Risk Assessment

a. Overview

The benefits (and costs) of a regulation are based on the difference between the baseline (*i.e.*, the *status quo*) and the 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. A probabilistic approach, however, could enhance and extend 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 in some cases by certain federal agencies including the U.S. Nuclear Regulatory Commission, Department of Homeland Security, and the National Aeronautics and Space Administration.

The basic modeling tools of probabilistic risk assessment 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 probabilistic risk assessment 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, 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.[58] 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

[58] For more information on how to develop and use event trees and fault tees in probabilistic risk assessments, see 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: Hazard 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 .

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 Potential Incidents of Non-Compliance (PINC). PINCs help to determine whether a facility is operating up to standards, although 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.

12. UMRA

This rule will not impose an unfunded Federal mandate on State, local, or tribal governments and will not have a significant or unique effect on State, local, or tribal governments. BSEE has determined that this rule will impose costs on the private sector of more than $100 million in a single year. Although these costs do not appear to trigger the requirement to prepare a written statement under UMRA, DOI has chosen to prepare a written statement satisfying the requirements of UMRA. Specifically, this final RIA, the RFA analysis for this rule, and the notice of final rulemaking itself constitute such a written statement.

Among other things, the final rule, this final RIA, or the RFA:

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

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

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

In addition, because all anticipated expenditures by the private sector analyzed in this final RIA and in the RFA analysis will be borne by a single segment of the private sector (the offshore oil and gas industry), this RIA and the RFA analysis satisfy the UMRA requirement to estimate any disproportionate budgetary effects of the rule on a particular segment of the private sector.

In addition, this final RIA describes BSEE's consideration of three major regulatory alternatives (*see* section 3). BSEE has decided to move forward with this 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 other blowouts resulting in the loss of well control, including another event with consequences similar to those of the *Deepwater Horizon* incident, or achieve the objectives of this rule.

BSEE has determined that the rule will not impose any unfunded mandates or any other requirements on State, local, or tribal governments; thus, the rule will not have disproportionate budgetary effects on these governments.

APPENDIX A: Rule Features that Were Considered Part of the Baseline

Exhibit A-1 presents rule features that were considered part of the baseline and, therefore, were not included in the analysis. They pertain to requirements with which each operator already complies (*e.g.*, under existing voluntary industry standards or under current BSEE rules, policy, or practice).

EXHIBIT A-1: Rule Features that Were Considered Part of the Baseline		**Baseline Basis**
§ 250.107(a)	General performance-based requirement that operators utilize recognized engineering practices that reduce risks to the lowest level practicable and conduct activities pursuant to the applicable lease, plan, or permit terms or conditions of approval.	Current industry practice to follow recognized engineering practices. Current § 250.107(a) requires operators to protect health, safety, and the environment and to comply with BAST. Current § 250.101(a) requires that all operations be conducted in accordance with OCSLA, the regulations, orders, and lease terms. Current § 250.146(a) and (b) requires lessees and operators to meet all obligations under the regulations and OCSLA.
§ 250.107(e)	Clarify BSEE's authority to issue orders when necessary to protect health, safety, property, or the environment or because the operations violate law, regulation, order, or provision of a lease, plan, or permit.	Current BSEE practice underauthority of OCSLA and §§ 250.172 and 250.173.
§ 250.414(c), § 250.427(b)	Changes to better define safe drilling margins.	Current BSEE practice under APD permit process pursuant to current § 250.410, *et seq*., including §§ 250.413(g) and 250.414(c). BSEE currently allows safe drilling margins as justified in APDs or APMs.
§ 250.414(k)	Additional information required by the BSEE District Manager.	BSEE District Managers currently have discretion to require additional information within the APD process under current § 250.418(j).
§ 250.415(a)	Requires specified information for all sections for each casing interval to make design calculations and submittals more accurate and provide a complete representation of the well.	Current BSEE practice under APD process pursuant to current § 250.410, *et seq*., including §§ 250.413 and 250.415, using readily available data from industry.
§ 250.418(g)	Requires operators to seek approval for plans to wash out or displace cement to facilitate casing removal upon well abandonment.	Current regulations - § 250.418(g).
§ 250.420(a)(6)	Adequate centralization to help ensure proper cementation.	Current industry standards (*e.g.*, API Standard 65-2).

§ 250.420(b)(4)	Specifies that if casing is needed that differs from what was approved in the APD, the operator would have to contact the appropriate District Manager and receive approval before installing the different casing.	Current BSEE practice with the well screening tool and APD permit process.
§ 250.420(c)(2)	Enhancement of the wellbore stability during cementing.	Current industry standards (*e.g.*, API Standard 65-2).
§ 250.421(b)	If oil, gas, or unexpected formation pressure is encountered, the operator would have to set conductor casing immediately and set it above the encountered zone. This ensures that conductor casing is not placed across a hydrocarbon zone.	Current practice based on current regulations - § 250.421(b).
§ 250.428(b)	Approval for hole interval drilling depth changes greater than 100 ft. TVD, and the submittal of a PE certification that the certifying PE reviewed and approved the proposed changes.	Current practice based on current regulations - § 250.420(a)(6).
§ 250.428(k)	Adds clarification concerning the use of valves on drive pipes during cementing operations for the conductor casing, surface casing, or liner. It also makes specific requirements to assist BSEE in assessing the structural integrity of the well.	Customary industry practice; reporting requirement covered by current regulations - § 250.468.
§ 250.462(c)	Requires submittal of a description of the source control and containment capabilities before BSEE would approve an APD.	Current BSEE practice and covered by NTL 2010-N10.
§ 250.462(d)	Operators must contact the District Manager and Regional Supervisor for reevaluation of the SCCE if there are any well design changes or if any of the approved SCCE is out of service.	Current BSEE practice with APD permit process and under current regulations - § 250.465.
§ 250.518(e)(2)	The production packer must be set at a depth that will allow for a column of weighted fluids to be placed above the packer that will exert a hydrostatic force greater than or equal to the force created by the reservoir pressure below the packer.	Current practice under current regulations – § 250.514.
§ 250.518(e)(4)	The production packer must be set at a depth that is within the cemented interval of the selected casing section.	Current practice consistent with industry standards; *e.g.*, API Spec 11D1 (operational parameters, environmental compatibility, and compatibility with related well equipment).
§ 250.518(new (f))	Requires inclusion in the APM of a description and calculations of how the production packer setting depth was determined.	Current practice consistent with industry standards; *e.g.*, API Spec 11D1 (operational parameters, environmental compatibility, and compatibility with related well equipment).
§ 250.710	Requires personnel engaged in well operations to be instructed in safety requirements, possible	Current practice and covered under current regulations - §§ 250.506, 250.606,

	hazards, and general safety considerations prior to engaging in operations.	and 250.1915 (SEMS).
§ 250.721(e)	Requires operators to follow additional pressure test requirements when they plan to produce a well.	Current practice under APD and APM permit process.
§ 250.721(f)	Requires a professional engineer (PE) certification of proposed plans to provide a proper seal if there is an unsatisfactory pressure test.	Current practice required for PE certifications under current regulations - § 250.420(a)(6).
§ 250.721(g)	Requires a negative pressure test on all wells that use a subsea BOP and outlines the requirements for those tests.	Current practice and covered under current regulations - § 250.423(c).
§ 250.722	Requirements for prolonged operations in a well. Helps ensure a proper wellbore integrity determination to allow operations to continue.	Current practice and covered under current regulations - § 250.424.
§ 250.731(e)	Requires a listing of the functions with sequences and timing of autoshear, deadman, and emergency disconnect sequence (EDS) systems.	Current practice under APD permit process consistent with current regulations - § 250.416(c).
§ 250.732	Requires equipment to be monitored during its lifecycle by an independent third-party to verify compliance with BSEE requirements.	Current practice and covered under current regulations - § 250.416.
§ 250.732(b)	Applicable to any operation that requires any type of BOP, and would require verification of shear testing, pressure integrity testing, and calculations for shearing and sealing pressures for all pipe to be used. Each of these verifications must demonstrate outlined specific requirements.	Current practice and covered under current regulations - § 250.416.
§ 250.734(b)	Codifies BSEE policy and requires that if operations are suspended to make repairs to the BOP, operations would have to be stopped at a safe downhole location. Helps BSEE ensure the BOPs have proper verification after repairs and that BSEE is aware of the repairs.	Current practice and covered under current regulations - § 250.451.
§ 250.734(c)	Codifies BSEE policy that if an operator plans to drill a new well with a subsea BOP, the operator does not need to submit with its APD the verifications required for the open water drilling operation.	Current practice under APD process and under current regulations - § 250.416.
§ 250.743(c)	Requires data to provide BSEE with accurate information regarding the operations and well conditions and verify the operator’s compliance with past approvals.	Current policy – covered under form BSEE-0133 and current regulations - § 250.468.
§ 250.746(e)	Leaks associated with the BOP or control system during testing must be documented. If any unrepairable problems are observed during	Current policy – covered under form BSEE-0133 and current regulations - §§

	testing, operations must be suspended until the District Manager determines that operations may continue.	250.468 and 250.451.

APPENDIX B: List of Incidents Used in Benefits Analysis

Exhibit B-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 B-1 include only incidents caused by LWCs from 1987 to 2010 that resulted in spills of 10 barrels of more. These data were obtained from the BOEMRE OCS Spill Database.

EXHIBIT B-1 : INCIDENTS USED IN BENEFITS ANALYSIS

Date	Total Spilled (Barrels)	Fatalities
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

(*1987 data for illustration; not included in Benefits analysis)

Source: BOEMRE OCS Spill Database, June 2011.

APPENDIX C: PRA Burden Table From the Final Rule

[Current regulations are regular font with an asterisk (*); *Italic* font show *revision(s)* of existing requirements; and **bold** font indicates **new** requirements]

BSEE-Approved Verification Organization = BAVO

30 CFR 250 Current *Revision* **NEW**	**Reporting & Recordkeeping Requirement+**	**Hour Burden**	**Average No. of Annual Responses**	**Annual Burden Hours (rounded)**
		Subpart A		
107(e)	Produce and submit documents ordered by BSEE to ensure compliance with this part.	Burden covered under various 30 CFR 250 regulations (depending on the operational requirement(s)).		0
141; 198; **701; 720(a)(2); 721(d); 730(d)(1);** 1612	Request approval to use new or alternative procedures, along with supporting documentation if applicable, including BAST not specifically covered elsewhere in regulatory requirements.	22	1,430 requests	31,460*
142; 198; **702**	Request approval of departure from operating requirements not specifically covered elsewhere in regulatory requirements, along with supporting documentation if applicable.	3.5	405 requests	1,418*
		Subtotal (A)	1,835 responses	32,878 hours*
		Subpart B		
287; 291; 292(*p*)	Submit DWOP and accompanying/ supporting information. *Provide detailed information/descriptions pertaining to pipeline free standing hybrid riser (FSHR). Submit documentation for pipeline FSHR certification and have verified by CVA.*	1,140 *4*	11 plans	12,540* *44*
		Subtotal (B)	11 responses	12,540 hours* *44 hours* 12,584 hours
		Applications for Permit to Drill (APD)		
410-418; 420(a); 423(c); **428(b), (k);** plus various references in Subparts A, D, E, F, **G (701; 702; 713(a), (b), (e),**	Apply for permit to drill APD (Form BSEE-0123) that includes any/all supporting documentation /evidence (including, but not limited to, test results, calculations, pressure integrity, kill weight fluids, verifications, certifications, procedures, criteria, qualifications, diverter descriptions*;* **planned safe drilling margin;** rig anchor pattern plats; contingency plan (move off info/**current monitoring**); description of your BOP and its components and schematic drawings; **descriptive schematic (pressure ratings, dimensions, valves, load shoulders;** locking mechanisms**; location of ruptured disks; description of mudline level to displace cement; how operator visually monitors returns; PE certification re**	114.98 **4**	408 applications	46,912* **1,632**

(g); 720(b); 721(g)(4); 724(b); 731; 733(b); 734 (c); 737(a)(3), (b)(2), (b)(3), (d)(2-4), (d)(12); 738(f), (m), (n); H; and P	**changes to casing setting depths; BAVO reports; description of source control and containment capabilities; EDS; pipe variable bore rams; annulus monitoring plan information; any additional information required by District Manager**; etc.) and requests for various approvals required in Subpart D (including §§ *250.414(h); 418(g);* 427, 428, 432, 460, 490(c)) and submitted via the form; upon request, make available to BSEE.			
420(b)(4); 428; 465(a)(1); **721(g)(4); 731; 734(c)**	Obtain approval to revise your drilling plan [changes to the casing], or change major drilling equipment by submitting a revised Form BSEE-0123, Application for Permit to Drill; **include BAVO certification; any other information required by the District Manager.**	1.34	662 submittals	888*
Subtotal (APD)			1,070 responses	47,800 hours* **1,632 hours** 49,432 hours
Application for Permit to Modify (APM)				
460; 465; ref in Subparts A, D, E *518(f);* F, *619(f)*; **G, 701; 702; 713(a), (b), (e), (g); 720(b); 721(g)(4); 724(b); 731; 733(b); 734(b)(1); 737(d)(2-4), (d)(12); 738(f), (m), (n)*;*** *H;* P; and Q *1704(g)*	Provide revised plans and the additional supporting information required by the cited regulations [test results; calculations; verifications; certifications, procedures; **descriptions/calculations of production packer setting depth**; **BAVO reports/certifications;** rig anchor pattern plats; contingency plan *(*move off info/**current monitoring**)*;* description of your BOP, its components and schematic drawings; [annulus monitoring plan information]; criteria; qualifications**;** etc.] when you submit an Application for Permit to Modify (APM) (Form BSEE-0124) to BSEE for approval.	2.841 **1.5**	2,893 applications	8,219* **4,340**
Subparts D, E, F, H, P, Q	Submit Revised APM plans (BSEE-0124). (This burden represents only the filling out of the form).	1	1,551 applications	1,551*
Subtotal (APM)			4,444 responses	9,770 hours* **4,340 hours** 14,110 hours
Subpart D				

420(b)(3); 465(a) *(b)(3);* plus various ref in A, D, E, F, **G, 721(g)(8); 744;** P; Q (1704**(h)**);	Submit form BSEE-0125 (End-of-Operations Report (EOR)) and all additional supporting information as required by the cited regulations; *and any additional information required by the District Manager.*	2	279 submittals	558*
		1		*279*
421(b)	Alaska only: Discuss the cement fill level with the District Manager.	1	1 discussion	1*
421(f)	Submit and receive approval if unable to cement 500 ft above previous shoe.	Burden covered under 30 CFR 250, Subpart A (§ 250.141/142) 1014-0022		0
423(c)(2)	Document all your test results and make them available to BSEE upon request.	0.5	300 results	150*
428(c)(3); **428(k); 743(a), (c); 746(e);** ref in Subparts A, D, **G**	In the GOM OCS Region, submit drilling activity reports weekly (District Manager may require more frequent submittals) on Forms BSEE-0133 (Well Activity Report (WAR)) and BSEE-0133S (Bore Hole Data) with supporting documentation.	1	4,160 submittals	4,160*
428(c)(3); **428(k); 743(b), (c)** ref in A, D, **G**	In the Pacific and Alaska Regions during drilling operations, submit daily drilling reports on Forms BSEE-0133 (Well Activity Report (WAR)) and BSEE-0133S (Bore Hole Data) with supporting documentation.	1	14 wells x 365 days x 20% year = 1,022	1,022*
428(d)	Submit all remedial actions for review and approval by District Manager (before taking action); and any other requirements of the District Manager.	5	1,000 submittals	5,000*
428(d)	*Submit descriptions of completed immediate actions to District Manager and any other requirements of the District Manager.*	*5*	*564 submittals*	*2,820*
428(d)	*Submit PE certification of any proposed changes to your well program; and any other requirements of the District Manager.*	*4*	*450 submittals*	*1,800*
428(k)	**NEW:** Maintain daily drilling report (cementing requirements).	**0.5**	**75 reports**	**38**
428(k)	**NEW:** If cement returns are not observed, contact the District Manager to obtain approval before continuing with operations.	**1**	**10 requests**	**10**
462(c)	**NEW:** Submit a description of source control and containment capabilities and all supporting information for approval.	**8**	**150 submittals**	**1,200**
462(d)	**NEW:** Request re-evaluation of your source containment capabilities from the District Manager and Regional Supervisor.	**1**	**600 requests**	**600**
462(e)(1)	**NEW:** Notify BSEE 21 days prior to pressure testing; witness by BSEE and BAVO.	**0.5**	**150 notifications**	**75**
			6,762 responses	10,891 hours*
			1,014 responses	*4,899 hours*

		Subtotal (D)	**985 responses**	**1,923 hours**
			8,761 responses	17,713 hours
	Subpart E			
518(f)	Include in your APM descriptions and calculations of production packer setting depth(s).	Burden covered under 1014-0026.		0
	Subpart F			
619(f)	Include in your APM descriptions and calculations of production packer setting depth(s).	Burden covered under 1014-0026.		0
	Subpart G			
	General Requirements			
701; 720(a); 730(d)(1) (250.141)	Request alternative procedures or equipment from District Manager; along with any supporting documentation/ information required.	Burden cover under 1014-0022.		0
702 (250.142)	Request departures from District Manager; include justification; and submit supporting documentation if applicable.	Burden cover under 1014-0022.		0
	Rig Requirements			
710(a)	Instruct crew members in safety requirements of operations - record dates and times of meetings, *include potential hazards; make available to BSEE.*	0.75	7,512 meetings	5,634*
710(b); 738(p)	Prepare a well-control drill plan for each well, including but not limited to instructions re components of BOP, procedures, crew assignments, established times to complete assignments, etc. Keep/post a copy of the plan on the rig at all times; post on rig floor/bulletin board.	0.5	308 plans	154*
711(b), (c)	Record in the daily report: time, date, and type of drill conducted; time re diverter or BOP components; total time for entire drill.	1	8,320 drills	8,320*
712(a), (b), (f)	Notify BSEE of all rig movements on or off locations.	0.1	20 notices	2*
	Rig movements reported on Rig Movement Notification Report (Form BSEE-0144). Including *MODUs,* platform rigs; snubbing units, *lift boats, wire-line units,* and coiled tubing units 24 hours prior to movement; *if the initial date changes by more than 24 hours, submit updated BSEE-0144.*	0.2	151 forms	30*
		0.2	*832 forms*	*166*
712(c), (e)	**NEW:** Notify District Manager if MODU or platform rig is to be warm or cold stacked on Form BSEE-0144; notify District Manager where the rig is coming from when entering OCS waters.	**0.5**	**50 notifications**	**25**
712(d)	**NEW:** Prior to resuming operations, report to District Manager any construction repairs or modifications that were made to the MODU or rig.	**2**	**10 responses**	**20**
713	Submit MODU information if being used for well operations with your APD/APM.	Burden covered under 1014-0025 for APD; and 1014-0026 for APM.		0
713(a), (b)	Collect and report additional information if sufficient information is not available.	5	30 responses	150*
			466 responses	*2,330*
713(b)	Reference to Exploration Plan, Development and	Burden covered under		0

	Production Plan, and Development Operations Coordination Document (30 CFR 550, Subpart B).	1010-0151.		
713(c)(1)	Submit 3rd party review of drilling unit according to 30 CFR 250, Subpart I.	Burden covered under 1014-0011.		0
713(c)(2); (417(c)(2)	Have a Contingency Plan that addresses design and operating limitations of MODU.	Burden covered under 1014-0025.		0
713(d) 417(d)	Submit current certificate of inspection/ compliance from USCG and classification; submit documentation of operational limitations by a classification society.	Burden covered under 1014-0025.		0
714	NEW: Develop and implement dropped objects plan with supporting documentation/ information; any additional information required by the District Manager; make available to BSEE upon request.	**40**	**40 plans**	**1,600**
715; NTL	GPS for MODUs 1 – Notify BSEE with tracking/locator data access and supporting information; notify BSEE Hurricane Response Team as soon as operator is aware a rig has moved off location.	0.25	1 rig 1 notification	1*
	2 –Install and protect tracking/locator devices – (these are replacement GPS devices or new).	20 devices per year for replacement and/or new x $325.00 = $6,500*.		
	3 – Pay monthly tracking fee for GPS devices already placed on MODUs.	40 rigs x $50/month = ($600/year per 1 rig) = $24,000*.		
	4 – Rent GPS devices and pay monthly tracking fee per MODU.	40 rigs @ $1,800 per year = $72,000*.		
			16,343 responses	14,291 hours*
			1,298 responses	*2,496 hours*
			100 responses	**1,645 hours**
			17,741 responses	18,432 hours
		Subtotal (G – Rig Req.)	$102,500 Non-hour cost burdens*	
Well Operations				
720(a)	**NEW:** Notify and obtain approval from the District Manager when interrupting operations.	**5**	**150 notifications**	**750**
720(a)(2)	Request approval to use alternate procedures/barriers.	Burden covered under 1014-0022.		0
720(b)	Submit with your APD or APM reasons for displacing kill-weight fluid with detailed procedures with relevant information of section.	Burden covered under 1014-0025 for APD; and 1014-0026 for APM.		0
721(d), (f), (g)	Submit to the District Manager for approval plans to re-cement, repair, or run additional casing/liner, include PE certification of proposed plans.	0.5	88 requests	44*
721(g)(4)	Submit test procedures and criteria for a successful test with APD/APM; if changes made to procedures, submit changes with revised APD or APM.	Burden covered under 1014-0025 for APD; and 1014-0026 for APM.		0
721(g)(5)	Document all your test results; make available to BSEE upon request.	0.75	1,340 results	1,005*
721(g)(6)	Notify District Manager immediately of indication of failed negative pressure test; submit description of corrective action taken; receive approval to retest.	1	14 notifications	14*
721(g)(8);	Submit Form BSEE-0125, EOR.	Burden covered under		0

744(a)		1014-0018.		
722	Caliper, pressure test, or evaluate casing; submit evaluation results report *including calculations*; obtain approval before *repairing or installing additional casing;* **PE Certification***;* or resuming operations (every 30 days during prolonged drilling).	3	247 reports	741*
722(b)(3)	**NEW:** Perform a pressure test after repairs made/casing installed and report results.	**1**	**300 results**	**300**
723(d)	Request exceptions prior to moving rig(s) or related equipment.	1.5	845 requests	1,268*
724	**NEW:** Transmit real-time monitoring (RTM) data onshore during operations or in HPHT reservoirs; store and monitor by qualified personnel. Provide BSEE access to RTM data storage locations upon request.	**2,160**	**30 rigs**	**64,800**
724(c)	**NEW:** Develop and implement a RTM plan that includes all required data of this section; make available to BSEE upon request.	**5**	**130 plans**	**650**
724(b)	**NEW**: Include in your APD a certification that you have such a plan and meet criteria of this section.	Burden covered under 1014-0025 for APD; and 1014-0026 for APM.		0
			2,534 responses	3,072 hours*
			610 responses	**66,500 hours**
	Subtotal (G – Well Op.)		3,144 responses	69,572 hours
	BOP System Requirements			
730(a)(4)	**NEW:** Maintain current set of approved schematic drawings on rig and onshore location; obtain approval to resume operations if modified/changed.	**24**	**10 requests**	**240**
730(c)(1)	**NEW:** Provide written notice within 30 days of discovery/identification of equipment failure.	**2**	**30 reports**	**60**
730(c)(2)	**NEW:** Provide BSEE and manufacturer a copy of analysis report re equipment failure.	**5**	**30 reports**	**150**
730(c)(3)	**NEW:** Document all results and any corrective action re failure analysis. Submit report re design change/modified procedures within 30 days of manufacturer's notification.	**5**	**2 reports**	**10**
730(d)(1)	**NEW:** Request alternate approval from using to API Spec. Q1.	**5**	**1 response**	**5**
731	Submit/resubmit BOP component information in APD/APM and certification that verifies changes or moved off location.	Burden covered under 1014-0025 for APD; and 1014-0026 for APM.		0
732(a)	**NEW:** Request and submit for approval all relevant information to become a BAVO.	**100**	**7 applications**	**700**
732(b)	**NEW:** Submit BAVO verification and all supporting documentation related to this section (such as, but not limited to shearing testing, pressure integrity testing, calculations, etc.).	**10**	**150 verifications**	**1,500**
732(c)	**NEW:** Submit verifications, before beginning operations in HPHT environment, that a BAVO conducted detailed reviews of the BOP and related equipment.	**10**	**10 wells**	**100**
732(d), (e)	**NEW:** Submit a BAVO Mechanical Integrity	**10**	**90 reports**	**900**

	Assessment Report that includes all information from this section; make all documentation available to BSEE upon request.			
733(b)(2)	**NEW:** Describe in your APD or APM your annulus monitoring plan.	Burden covered under 1014-0025 for APD; and 1014-0026 for APM.		0
734(a)(7)	Demonstrate acoustic control system will function properly in environment and conditions; *submit any additional information requested.*	5	1 validation	5*
		1	*10 submittals*	*10*
734(a)(9); 738(n)	Label all functions on all panels.	1.5	33 panels	50*
734(a)(10)	Develop written procedures for operating the BOP stack, LMRP, and minimum knowledge requirements for personnel authorized to operate/maintain BOP components.	Burden covered under 1014-0018.		0
734(b), (c)	*Before resuming operations, submit a revised APD/APM with BAVO report documenting repairs*; perform a new BOP test upon relatch, etc.; receive approval from the District Manager.	Burden covered under 1014-0025 for APD; and 1014-0026 for APM.		0
737(a)(3), (a)(4); (b)(2), (b)(3); (d)(2-4), (d)(12)	In your APD: submit stump, initial, or pressure tests; and subsea BOP procedures and supporting relevant data/information including, but not limited to, casing string and liner; quick disconnect procedures with your deadman test procedures, etc. Obtain approval of test pressures.	Burden covered under 1014-0025.		0
737(c); 746(a), (b), (c), (d)	Record time, date, and results of all pressure tests, actuations, and inspections of the BOP system, its components, and marine riser in the daily report; onsite rep certify and sign/date reports, etc.; document sequential order of BOP, closing times, auxiliary testing, pressure, and duration of each test.	7.75	4,457 results	34,542*
737(d)(2), (d)(3), (d)(4);	Notify District Manager 72 hours prior to testing; if BSEE unable to witness test, provide results to BSEE within 72 hours after completion; document all ROV test results; make available to BSEE upon request.	0.25	186 notifications	47*
		5.5	1,239 results	6,815*
737(d)(12)	Document all autoshear, *EDS*, and deadman test results; make available to BSEE upon request.	0.5	2,520 submittals	1,260*
		1	*120 responses*	*120*
737(e)	Provide 72 hour advance notice of location of shearing ram tests or inspections.	0.25	136 notices	34*
738; 746(e)	**NEW**/*Revised*: Requires District Manager Approval: (a), (d); 746(e) Report problems, issues, leaks; (b) Put well in a safe condition; (b) Prior to resuming operations for new/repaired/reconfigured BOP (*g) Your well control places demands above its rating pressure;* (j) Two barriers in place prior to BOP removal.	**0.5**	**25 requests**	**13**
		1	**25 requests**	**25**
		1	**25 requests**	**25**
		0.25	200 requests	50*
		1	*15 requests*	*15*
		1	**1 request**	**1**
738(b), (i)	**NEW:** Submit a BAVO report/verification that BOP is fit for service.	**0.5**	**50 submittals**	**25**
738(f)	**NEW:** Notify District Manager of BOP configuration changes.	**0.5**	**15 submittals**	**8**

738(g)	**NEW:** Demonstrate well-control procedures will not place demands above its working pressure.	**1**	**15 submittals**	**15**
738(k)	**NEW:** Contact and obtain for approval prior to latching up BOP stack/re-establishing power.	**1**	**2 requests**	**2**
738(m)	**NEW:** Request approval in your APD or APM to utilize any other well-control equipment.	Burden covered under 1014-0025 for APD; and 1014-0026 for APM.		0
738(m)	**NEW:** Request approval to utilize any other well-control equipment; include BAVO report re-equipment design and suitability; any other documentation/information required by District Manager.	**2**	**10 requests**	**20**
738(n)	**NEW:** Include in your APD or APM which pipe/variable bore rams meet the criteria.	Burden covered under 1014-0025 for APD; and 1014-0026 for APM.		0
738(o)	**NEW:** Submit BAVO report re failure of redundant control and confirming no impact to the BOP that makes it unfit; receive approval to continue operations; submit any additional information requested by the District Manager.	**1**	**15 submittals**	**15**
739	Document **how you meet/exceed API Standard 53;** maintain complete records; **track/document all inspection dates**; maintain all records including but not limited to **equipment schematics**, maintenance, inspection, repair, etc., for 2 years or longer if directed on the rig; all **equipment schematics**, maintenance, inspection, repair records are located onshore for service life of equipment; make available to BSEE upon request.	9.75	350 records	3,413*
739(b)	**NEW:** A BAVO report documenting inspection, including problems and how corrected; make reports available to BSEE upon request.	**5**	**21 reports**	**105**
			9,122 responses	46,216 hours*
			145 responses	*145 hours*
			534 responses	**3,919 hours**
		Subtotal (G – BOP SR)	9,801 responses	50,280 hours
	Records and Reporting Requirement			
740; 711(b); 724(b); 738(c); 745; 746	Maintain daily report/records onsite during operations include, but not limited to, **date, time, type of drill**, test results; any information required by the District Manager.	25 min	312 reports	130*
		1	**25 responses**	**25**
740; 741; 724(b)	Retain drilling records for 90 days after drilling complete; retain casing/liner pressure, diverter, BOP tests, **real-time monitoring data** for 2 years after completion; any other information requested by the District Manager.	2.15	3,460 records	7,439*
		0.5	**120 records**	**60**
742; NTL	Submit copies of logs/**charts of electrical, radioactive, sonic,** or other well logging operations.	3	281 logs/ surveys	843*
	Submit copies of directional and vertical-well surveys.	1	281 reports	281*

	Submit copies of velocity profiles and surveys.	1	55 reports	55*
	Record and submit core analyses.	1	150 analyses	150*
743(a), (c)	In the GOM OCS Region, submit Well Activity Reports (WARs) weekly (District Manager may require more frequent submittals) on BSEE-0133 and BSEE-0133S (Open Hole Data Report) with supporting information described in this section; *any additional information required by the District Manager.*	Burden covered under 1014-0018.		0
743(b), (c)	In the Pacific and Alaska OCS Regions during operations, submit WARs daily (BSEE-0133 and BSEE-0133S); with supporting information described in this section; *any additional information required by the District Manager*.	Burden covered under 1014-0018.		0
744	Submit form BSEE-0125, EOR.	Burden covered under 1014-0018.		0
745; NTL	Submit copies of well records; paleontological interpretations; service company reports; and other reports or records of operations to BSEE as requested.	1.5	308 submissions	462*
746	Record the time, date, and results of all casing and liner presser tests.	2	4,160 results	8,320*
746(f)	Retain all records pertaining to pressure tests, actuations, and inspections in daily report etc.; retain all records listed in this section on the rig unit for the duration of operation; after completion, retain all records listed in this section for 2 years on rig unit and at the lessee's field office conveniently available to BSEE; make all the records available upon request.	1.5	1,563 records	2,345*
			10,570 responses	20,025 hours*
			145 responses	**85 hours**
		Subtotal (G – Rec. & Rpt. Req.)	10,715 responses	20,110 hours
	Subpart P			
1612	Request exception from 30 CFR 250.711 requirements.	Burden covered under 1014-0006.		0
	Subpart Q			
1704(g), **(h)**	Submit Forms BSEE-0124 and BSEE-0125; include all supporting documentation/ information.	Burden covered under 1014-0018 for BSEE-0125; and 1014-0026 for BSEE-0124.		0
		Current burden	52,691 responses	197,483 hours*
		Revised burden	*2,457 responses*	*7,584 hours*
		NEW burden	**2,374 responses**	**80,044 hours**
Grand Total			57,522 Responses	285,111 Hours
			$102,500 Non-Hour Cost Burden	