DEPARTMENT OF THE INTERIOR

Bureau of Safety and Environmental Enforcement

30 CFR Part 250

[Docket ID: BSEE–2015–0002; 15XE1700DX EEEE500000 EX1SF0000.DAQ000]

RIN 1014–AA11

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

AGENCY: Bureau of Safety and Environmental Enforcement (BSEE), Interior.

ACTION: Proposed rule.

SUMMARY: The Bureau of Safety and Environmental Enforcement (BSEE) proposes new regulations in order to consolidate equipment and operational requirements that are common to other subparts pertaining to offshore oil and gas drilling, completions, workovers, and decommissioning. This proposed rule would focus, at this time, on blowout preventer (BOP) requirements, including incorporation of industry standards and revising existing regulations. The proposed rule would also include reforms in the areas of well design, well control, casing, cementing, real-time well monitoring, and subsea containment. The proposed rule would address and implement multiple recommendations resulting from various investigations of the *Deepwater Horizon* incident. This proposed rule would also incorporate guidance from several Notices to Lessees and Operators (NTLs) and revise provisions related to drilling, workover, completion, and decommissioning operations to enhance safety and environmental protection.

DATES: Submit comments by June 16, 2015. The BSEE may not consider comments received after this date. Submit comments to the Office of Management and Budget (OMB) on the information collection burden in this proposed rule by May 18, 2015. This does not affect the deadline for the public to comment to BSEE on the proposed regulations.

ADDRESSES: You may submit comments on the proposed rulemaking by any of the following methods. Please use the Regulation Identifier Number (RIN) 1014–AA11 as an identifier in your message. *See* also Public Availability of Comments under Procedural Matters.

• Electronic comments: *http://www.regulations.gov.* In the Search box, enter BSEE–2015–0002 then click search. Follow the instructions to submit public comments and view supporting and related materials available for this rulemaking. We will post all comments.

• Mail or hand-carry comments to the Department of the Interior (DOI); Bureau of Safety and Environmental Enforcement; Attention: Regulations and Standards Branch; 45600 Woodland Road, Sterling, Virginia 20166. Please reference *Blowout Preventer Systems and Well Control, 1014–AA11* in your comments and include your name and return address.

• Send comments on the information collection in this rule to: OMB, Interior Desk Officer 1014–NEW, 202–395–5806 (fax); email: *OIRA_submission@omb.eop.gov.* Please also send a copy to BSEE at *regs@bsee.gov,* fax number (703)787–1546, or by the address listed above.

FOR FURTHER INFORMATION CONTACT: Kirk Malstrom, Regulations and Standards Branch, 202–258–1518, *Kirk.Malstrom@bsee.gov.* To see a copy of the information collection request submitted to OMB, go to *http://www.reginfo.gov* (select Information Collection Review, Currently Under Review).

SUPPLEMENTARY INFORMATION:

List of Acronyms and References

ANSI American National Standards Institute
APD Application for Permit to Drill
API American Petroleum Institute
APM Application for Permit to Modify
BOP Blowout Preventer
BOEM Bureau of Ocean Energy Management
BSEE Bureau of Safety and Environmental Enforcement
BSR Blind Shear Ram
CBM Condition-based Maintenance
CVA Certified Verification Agent
DHS Department of Homeland Security
DOI Department of the Interior
DWOP Deepwater Operations Plan
ECD Equivalent Circulating Density
EDS Emergency Disconnect Sequence
E.O. Executive Order
EOR End of Operations Report
F Fahrenheit
FPS Floating Production System
FPSO Floating Production, Storage, and Offloading Unit
FSHR Free Standing Hybrid Risers
GOM Gulf of Mexico
GPS Global Position Systems
HPHT High Pressure High Temperature
JIT Joint Investigation Team
LMRP Lower Marine Riser Package
MASP Maximum Anticipated Surface Pressure
MMS Minerals Management Service
MODUs Mobile Offshore Drilling Units
NAE National Academy of Engineering
NAICS North American Industry Classification System
NARA National Archives and Records Administration
National Commission National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling
NTLs Notices to Lessees and Operators
OCS Outer Continental Shelf
OCSLA Outer Continental Shelf Lands Act
OEM Original Equipment Manufacturer
OIRA Office of Information and Regulatory Affairs
OMB Office of Management and Budget
PE Professional Engineer
psi Pounds per square inch
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
RIN Regulation Identifier Number
ROV Remotely Operated Vehicle
RP Recommended Practice
SBA Small Business Administration
SBREFA Small Business Regulatory Enforcement Act of 1996
SCCE Source Control and Containment Equipment
Secretary Secretary of the Interior
SEM Subsea Electronic Module
SEMS Safety and Environmental Management
Spec. Specification
TAR Technical Assessment and Research
TLP Tension Leg Platform
TVD True Vertical Depth
USCG United States Coast Guard
VSL Value of a Statistical Life
WAR Well Activity Report

Executive Summary

Following the *Deepwater Horizon* incident on April 20, 2010, multiple investigations were conducted to determine the causes of the incident and to make recommendations to reduce the likelihood of a similar incident in the future. The investigative groups included:

—DOI/Department of Homeland Security (DHS) Joint Investigation Team;
—National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling;
—Chief Counsel for the National Commission; and
—National Academy of Engineering.

Each investigation outlined several recommendations to improve offshore safety. The BSEE evaluated the recommendations and acted on a number of them quickly to improve offshore operations while other recommendations required additional input from industry and other stakeholders. The requirements in this proposed rule are based on recommendations made by the previously listed investigative bodies, which found a need to enhance well-control best practices to advance safety and protection of the environment.

This proposed rulemaking would:

(1) Incorporate the following industry standards:

—American Petroleum Institute (API) Standard 53, Blowout Prevention Equipment Systems for Drilling Wells;
—American National Standards Institute (ANSI)/API Specification (Spec.) 11D1, Packers and Bridge Plugs; and
—API Recommended Practice (RP) 17H, Remotely Operated Tools and Interfaces on Subsea Production Systems.

As related to BOP systems:
—ANSI/API Spec. 6A, Specification for Wellhead and Christmas Tree Equipment;
—ANSI/API Spec. 16A, Specification for Drill-through Equipment;
—API Spec. 16C, Specification for Choke and Kill Systems;
—API Spec. 16D, Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment; and
—ANSI/API Spec. 17D, Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment.

(2) Revise the requirements for Deepwater Operations Plan (DWOP) which are required to be submitted to BSEE, to include requirements on free standing hybrid risers (FSHR) for use with floating production, storage, and offloading units (FPSO).

(3) Revise sections in 30 CFR part 250 Subpart D, *Oil and Gas Drilling Operations,* to include requirements for:
—Submittal of equivalent circulating density (ECD) with the Application for Permit to Drill (APD);
—Safe drilling margin;
—Wellhead description;
—Casing or liner centralization during cementing; and
—Source control and containment.

(4) Revise sections in Subparts E, *Oil and Gas Well-Completion Operations,* and F, *Oil and Gas Well-Workover Operations,* to include requirements for:
—Packer and bridge plug design, and
—Production packer setting depth.

(5) Revise sections in Subpart Q, *Decommissioning Activities,* to include requirements for:
—Packer and bridge plug design,
—Casing bridge plugs, and
—Decommissioning applications and reports.

(6) Add new Subpart G, *Well Operations and Equipment,* and move common requirements from Subparts D, E, F, and Q into new Subpart G.

Include new requirements in Subpart G for:
—Rig and equipment movement reports,
—Real-time monitoring, and
—Revised BOP requirements, including:
—Design and manufacture/quality assurance;
—Accumulator system capabilities and calculations;
—BOP and remotely operated vehicle (ROV) capabilities;
—BOP functions (*e.g.,* shearing);
—Improved and consistent testing frequencies;
—Maintenance;
—Inspections;
—Failure reporting;
—Third-party verification; and
—Additional submittals to BSEE including up-to-date schematics.

(7) Incorporate the guidance from several Notices to Lessees and Operators (NTLs) into Subpart G for:
—Global Position Systems (GPS) for Mobile Offshore Drilling Units (MODUs);
—Ocean Current Monitoring;
—Using Alternate Compliance in Safety Systems for Subsea Production Operations;
—Standard Reporting Period for the Well Activity Report (WAR); and
—Information to include in the WARs and End of Operation Reports (EOR).

Table of Contents

I. Background

BSEE

In relation to oil and gas exploration, development, and production operations on the Outer Continental Shelf (OCS), the Bureau of Safety and Environmental Enforcement (BSEE) regulates offshore oil and gas operations to promote safety, protect the environment, and conserve offshore oil and gas resources. The BSEE was established on October 1, 2011, as part of a major restructuring of DOI's offshore oil and gas regulatory programs to improve the management, oversight, and accountability of activities on the OCS. The Secretary of the Interior (Secretary) announced the new division of responsibilities of the former Minerals Management Service (MMS) into two new bureaus and one office within DOI in Secretarial Order No. 3299, issued on May 19, 2010. The BSEE, one of the two new bureaus, assumed responsibility for ''safety and environmental enforcement functions including, but not limited to, the authority to permit activities, inspect, investigate, summon witnesses and [require production of] evidence[;] levy penalties; cancel or suspend activities; and oversee safety, response and removal preparedness'' (76 FR 64432, October 18, 2011).

BSEE Statutory and Regulatory Authority

The BSEE derives its authority primarily from the Outer Continental Shelf Lands Act (OCSLA), 43 U.S.C. 1331–1356a. Congress enacted OCSLA in 1953, establishing Federal control over the OCS and authorizing the Secretary to regulate oil and gas exploration, development, and production operations on the OCS. The Secretary has authorized BSEE to perform these functions under 30 CFR 250.101.

To carry out its responsibilities, BSEE regulates offshore oil and gas operations to enhance the safety of offshore exploration and development of oil and gas on the OCS and to ensure that those operations protect the environment and implement advancements in technology. The BSEE also conducts onsite inspections to assure compliance with regulations, lease terms, and approved plans. Detailed information concerning BSEE's regulations and guidance to the offshore oil and gas industry may be found on BSEE's Web site at: *http://www.bsee.gov/Regulations-and-Guidance/index.aspx.*

The BSEE regulatory program regulates a wide range of facilities and activities, including drilling, completion, workover, production, pipeline, and decommissioning operations. Drilling, completion, and workover operations are types of well operations offshore operators perform throughout the OCS from fixed and floating facilities. These well operations are the primary topic of this proposed rulemaking.

Ensuring the integrity of the wellbore and maintaining control over the pressure and fluids during well operations are critical aspects of protecting worker safety and the environment. The investigations that followed the *Deepwater Horizon* incident documented gaps or deficiencies in the OCS regulatory programs and made recommendations for improvements. The objective of this rulemaking is to address many of these recommendations, especially those related to BOP system design, performance, and reliability.

The BOP equipment and systems are critical components of many well operations. The BOP systems can be the last defense against a release of hydrocarbons into the environment, when all other forms of well control have failed (*e.g.,* the drilling fluid program). The BOPs may be the last line of defense in preventing release of gas that is volatile and considered to be an extreme safety hazard to rig personnel (uncontrolled gas releases can lead to explosions). The primary purpose of BOP systems is to prevent the uncontrolled release of hydrocarbons in an emergency situation by mechanically closing valves or rams that block the flow of fluid from the well. In some situations, this may require shear rams on the BOP stack to sever the drill pipe before the well can be sealed.

The BOP equipment and systems have increased in complexity as the industry moves into deeper water and develops reservoirs with pressures greater than 15,000 pounds per square inch (psi) or temperatures greater than 350 degrees Fahrenheit (F). Reservoirs with these conditions are considered high pressure high temperature (HPHT). Most of the BOPs that are used in deep water operations (400 to 10,000 feet) are located on the seabed, which presents technological and operational challenges. Additionally, HPHT operations create special metallurgical and design issues.

In this rulemaking, BSEE intends to:

- Implement many of the recommendations related to well-control equipment and fill gaps in the regulatory program.
- Increase the performance and reliability of well-control equipment, especially BOPs.
- Improve regulatory oversight over the design, fabrication, maintenance, inspection, and repair of critical equipment.
- Gain information on leading and lagging indicators of BOP component failures, identify trends in those failures, and help prevent accidents.
- Ensure that the industry uses recognized engineering practices, as well as innovative technology and techniques to increase overall safety.

Availability of Incorporated Documents for Public Viewing

When a copyrighted technical industry standard is incorporated by reference into our regulations, BSEE is obligated to observe and protect that copyright. The BSEE provides members of the public with Web site addresses where these standards may be accessed for viewing—sometimes for free and sometimes for a fee. Standards-developing organizations decide whether to charge a fee. The API provides free online public access to key industry standards, including a broad range of technical standards. These free standards represent almost one-third of all API standards and include all that are safety-related or have been or are proposed to be incorporated into Federal regulations, including the standards in this rule. These standards are available for online review, and hardcopies and printable versions will continue to be available for purchase. We are proposing to incorporate certain API standards. The API Web site address is: *http://www.api.org/publications-standards-and-statistics/publications/government-cited-safety-documents.*

For the convenience of the viewing public, who may not wish to purchase or view these proposed documents online, they may be inspected at BSEE, 45600 Woodland Road, Sterling, Virginia 20166; phone: 703–787–1665; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal-register/cfr/ibr-locations.html.*

These documents, if incorporated in the final rule, would continue to be made available to the public for viewing when requested. Specific information on where these documents can be inspected or obtained can be found at 30 CFR 250.198, *Documents incorporated by reference.*

Summary of Documents Incorporated by Reference

This rulemaking is substantive in terms of the content that is explicitly stated in the rule text itself, but it also incorporates by reference some very technical, detailed standards and specifications in the topic of blowout preventers and well control. In their aggregate this represents one of the most substantial rulemakings in the history of the BSEE and its predecessor organizations. A brief summary, based on the descriptions in each standard or specification, is provided in the text that follows.

API Standard 53—Blowout Prevention Equipment Systems for Drilling Wells

This standard is to provide requirements for the installation and testing of blowout prevention equipment systems whose primary functions are to confine well fluids to the wellbore, provide means to add fluid to the wellbore, and allow controlled volumes to be removed from the wellbore. Blowout preventer equipment systems are comprised of a combination of various components that are covered by this document. Equipment arrangements are also addressed. The components covered include:

Blowout preventers (BOPs) including installations for surface and subsea BOPs;

Choke and kill lines;

Choke manifolds;

Control systems; and

Auxiliary equipment.

This document provides new industry best practices related to:

The use of double shear rams

Maintenance and testing requirements.

Failure Reporting

Diverters, shut-in devices, and rotating head systems (rotating control devices) whose primary purpose is to safely divert or direct flow rather than to confine fluids to the wellbore are not addressed. Procedures and techniques for well control and extreme temperature operations are also not included in this standard.

API Recommended Practice 2RD—Design of Risers for Floating Production Systems and Tension-Leg Platforms

This document addresses structural analysis procedures, design guidelines, component selection criteria, and typical designs for all new riser systems used on Floating Production Systems (FPSs and Tension-Leg Platforms (TLPs). The presence of riser systems within an FPS has a direct and often significant effect on the design of all other major equipment subsystems. This RP includes recommendations on: (1) Configurations and components, (2) general design considerations based on environmental and functional requirements, and (3) materials considerations in riser design.

API Specification Q1—Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry

This specification establishes the minimum quality management system requirements for organizations that manufacture products or provide manufacturing-related processes under a product specification for use in the petroleum and natural gas industry. This document requires that equipment be fabricated under a quality management system that provides for continual improvement, emphasizing defect prevention and the reduction of variation and waste in the supply chain and from service providers. The goal of this specification is to increase equipment reliability through better manufacturing controls.

API Specification 6A—Specification for Wellhead and Christmas Tree Equipment

This specification defines minimal requirements for the design of valves, wellheads and Christmas tree equipment that is used during drilling and production operations. This specification includes requirements related to dimensional and functional interchangeability, design, materials, testing, inspection, welding, marking, handling, storing, shipment, purchasing, repair and remanufacture.

ANSI/API Specification 11D1—Packers and Bridge Plugs

This specification provides minimum requirements and guidelines for packers and bridge plugs used downhole in oil and gas operations. The performance of this equipment is often critical to maintaining control of a well during drilling or production operations. This specification provides requirements for the functional specification and technical specification, including design, design verification and validation, materials, documentation and data control, repair, shipment, and storage.

ANSI/API Specification 16A—Specification for Drill-Through Equipment

This specification defines requirements for performance, design, materials, testing and inspection, welding, marking, handling, storing and shipping of BOPs and drill-through equipment used for drilling for oil and gas. It also defines service conditions in terms of pressure, temperature and wellbore fluids for which the equipment will be designed. This standard is applicable to and establishes requirements for the following specific equipment: ram blowout preventers; ram blocks, packers and top seals; annular blowout preventers; annular packing units; hydraulic connectors; drilling spools; adapters; loose connections; and clamps.

Conformance to this standard is necessary to ensure that this critical safety equipment has been designed and fabricated in a manner that ensures reliable performance.

API Specification 16C—Specification for Choke and Kill Systems

This specification was formulated to provide for safe and functionally interchangeable surface and subsea choke and kill systems equipment utilized for drilling oil and gas wells. This equipment is used during emergencies to circulate out a ''kick'' and therefore, the design and fabrication of the components is extremely important. The technical content in the document provides the minimum requirements for performance, design, materials, welding, testing, inspection, storing and shipping. Equipment specific to and covered by this specification includes:

Actuated valve control lines;
Articulated choke & kill line;
Drilling choke actuators;
Drilling choke control lines, exclusive of BOP control lines;
Subsurface safety valve control lines;
Drilling choke controls;
Drilling chokes;
Flexible choke and kill lines;
Union connections;
Rigid choke and kill lines; and
Swivel unions.

API Specification 16D—Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment

This specification establishes design standards for systems that are used to control BOPs and associated valves that control well pressure during drilling operations. Although diverters are not considered well control devices, their controls are often incorporated as part of the BOP control system. Thus, control systems for diverter equipment are included in the specification. Control systems for drilling well control equipment typically employ stored energy in the form of pressurized hydraulic fluid (power fluid) to operate (open and close) the BOP stack components. For deepwater operations, transmission subsea of electric/optical (rather than hydraulic) signals may be used to short response times. The failure of these controls to perform as designed can result in a major well control event. As a result, conformance to this specification is critical to ensuring that the BOPs and related equipment will operate in an emergency.

ANSI/API Specification 17D—Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment

This specification provides specifications for subsea wellheads, mudline wellheads, drill-through mudline wellheads and both vertical and horizontal subsea trees. These devices are located on the seafloor, and therefore, ensuring the safe and reliable performance of this equipment is extremely important. This document specifies the associated tooling necessary to handle, test and install the equipment. It also specifies the areas of design, material, welding, quality control (including factory acceptance testing), marking, storing and shipping for both individual sub-assemblies (used to build complete subsea tree assemblies) and complete subsea tree assemblies.

API Recommended Practice 17H—Remotely Operated Tools and Interfaces on Subsea Production Systems

This recommended practice has been prepared to provide general recommendations and overall guidance for the design and operation of remotely operated tools (ROT) comprising ROT and ROV tooling used on offshore subsea systems. ROT and ROV performance is critical to ensuring safe and reliable deepwater operations and this document provides general performance guidelines for the equipment.

Deepwater Horizon Investigations

This section discusses relevant investigations that have significant bearing on this proposed rulemaking.

DOI/DHS Investigation

The joint DOI/DHS investigation started on April 27, 2010, when the Secretaries of DOI and DHS convened a joint investigation team (JIT) comprised of staff from the MMS and the U.S. Coast Guard (USCG). The JIT held seven public hearings and heard testimony from more than 80 witnesses. The DOI JIT issued a report on September 14, 2011, entitled, *REPORT REGARDING THE CAUSES OF THE APRIL 20, 2010 MACONDO WELL BLOWOUT,* which included its findings, conclusions, and recommendations.

National Commission

On May 22, 2010, President Barack Obama announced the creation of the *National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling* (National Commission), an independent, non-partisan entity. The President charged the National Commission to determine the causes of the disaster, to make recommendations for improvement to the country's ability to respond to spills, and to recommend reforms to make offshore energy production safer. The National Commission published its final report on January 11, 2011, entitled, *DEEP WATER, The Gulf Oil Disaster and the Future of Offshore Drilling.*

Chief Counsel for the National Commission

Given the factual and technical complexity of some of the underlying causes of the blowout, the National Commission's Chief Counsel issued a separate report setting forth in greater detail its findings and conclusions regarding the technical, managerial, and regulatory aspects of the blowout. The report contains findings and conclusions about the loss of well control, and also contains recommendations to industry and government to enhance well design. The Chief Counsel's report was published on February 17, 2011, and is entitled, *Macondo: The Gulf Oil Disaster.*

National Academy of Engineering

At the request of DOI, a National Academy of Engineering (NAE)/National Research Council committee examined the probable causes of the *Deepwater Horizon* explosion, fire, and oil spill in order to identify measures for preventing similar harm in the future. The final report was released December 14, 2011, and is entitled, *Macondo Well-Deepwater Horizon Blowout.* The final report provides findings about the causes of the loss of well control and the failure of the BOP to prevent release of hydrocarbons and offers recommendations to industry and government that would strengthen oversight of deepwater wells, enhance system safety, and improve cementing practices and the technical skills of industry and regulatory staff.

Recommendations on BOPs

Each of the previously discussed investigations resulted in reports that contained recommendations to improve offshore safety. One consistent element in each of the investigations was the recognition that additional requirements related to BOPs and well-control equipment are needed. The following list contains some of the recommendations on BOPs and related equipment from the various investigations:

—The BSEE should consider promulgating regulations that require operators/contractors to have the capability to monitor the subsea electronic module (SEM) battery(ies) from the drilling rig, to ensure that there is sufficient battery power to operate the system.
—The BSEE should consider requiring standardization of: Remotely Operated Vehicle (ROV) intervention panels, ROV intervention capabilities, and maximum closing times when using an ROV; ROV hot stab and receptacles per API RP 17H; and hot stab designs between drilling and production operations.
—The BSEE should consider requiring a blind-shear ram design that incorporates improved pipe-centering in the shear ram.
—The BSEE should make effective use of industry standards and best practice guidelines used by other countries with the recognition that standards need to be updated and revised continually.
—The BSEE should improve reporting of safety-related incidents and require the reporting of near-misses to assist in accident prevention and to improve standards.
—The BSEE should develop standardized requirements for the training and certification of key industry personnel.
—The BSEE should rely on independent organizations to verify and certify compliance with critical designs and required processes.
—The BSEE should ensure that the general well design includes a review of fitness of the components for the intended use.
—The BSEE should consider promulgating regulations that would require operators to report leaks associated with BOP control systems.
—The BSEE should consider promulgating regulations that would require real-time, remote capture of drilling data and BOP function data.
—The BSEE should require improvement of the instrumentation on BOP systems so that the functionality and condition of the BOP can be monitored continuously.
—The BSEE should consider regulations that address a reasonable margin of safety between the ECD and the pressure that would cause wellbore fracturing.
—The BSEE should establish testing and maintenance requirements for BOPs to ensure operability and increased reliability appropriate to the environment and application.
—The BSEE should require improvement of the design capabilities of the BOP systems so that they can shear and seal all combinations of pipe under all possible conditions of load from the pipe and from the well flow, and so that there would always be a shearable section of the drill pipe in front of a blind-shear ram in the BOP.
—The BSEE should require demonstration of the performance of the design capabilities of BOPs and require that they be independently certified on a regular basis by test or other means.

Stakeholder Participation

Since the *Deepwater Horizon* incident, BSEE has made it a priority to participate in meetings, training, and workshops with industry, standards organizations, and other stakeholders. The BSEE recognized that it was important to collect the best ideas on the prevention of well-control incidents and blowouts to assist in the development of this proposed rule. This includes the knowledge and skillset that industry has, and BSEE wants to benefit from that experience to improve the safety of all operations on the OCS.

Therefore, on May 22, 2012, BSEE hosted a public offshore energy safety forum that brought together Federal decision-makers, industry, academia, and other stakeholders to discuss additional steps that BSEE and the industry might take to continue to improve the reliability and safety of BOPs. This public forum provided industry experts, Federal decision-makers, and the public the opportunity for free and open dialogue. Discussion panels consisted of representatives from government organizations, trade associations, equipment manufacturers, offshore operators, consultants, training companies, and others. During the forum, five separate panels discussed the following BOP topics:

—BOP technology needs identified by *Deepwater Horizon* investigations;
—Real-time technologies that can aid in diagnostics and kick detection;
—Design requirements needed to provide assurance that BOPs would cut casing or drill pipe and seal a well effectively;
—Manufacturing, testing, maintenance, and certification requirements needed to ensure operability and reliability of BOP equipment; and
—Training and certification needs for industry personnel operating or maintaining BOPs.

You can find additional information about the forum, including presentations and transcripts, on the BSEE Web page at: *http://www.bsee.gov/BSEE-Newsroom/BSEE-News-Briefs/2012/BSEE-Hosts-BOP-Forum-in-DC.* In the year following this forum, BSEE has also received significant input and specific recommendations from industry groups, operators, equipment manufacturers, and environmental organizations on each of these items. For example, BSEE has actively participated in the following, among other events:

—The API Exploration & Production Standards Conference on Oilfield Equipment and Materials;
—The Ocean Energy Safety Institute risk forum;
—The Offshore Well Control Equipment Forum, organized by API, January 30, 2014;
—The International Regulators Forum;
—Various standards committees and sub-committees for standards development (*e.g.,* API Committee on Standardization of Oilfield Equipment and Material Subcommittee 16 on Drilling Well Control Equipment);
—The BSEE and industry assessments of current technology involving research that BSEE is funding; and
—The BSEE sponsored standards workshops—November 2012 and January 2014.

The BSEE has considered this input in developing this proposed rulemaking and has reviewed studies and research on this topic.

BSEE Response to Recommendations and Additional Considerations

The BSEE evaluated all recommendations from the investigative bodies and public input and determined that the agency needs to update regulations related to the prevention of blowouts. The prevention of blowouts, either through precautionary measures or by operation of a BOP, is a critical priority for BSEE. The BSEE therefore focused this rulemaking on updating and revising current well-control regulations.

Several of the recommendations related to BSEE's regulatory programs were already implemented in rulemakings following the *Deepwater Horizon* incident. The following items are included in this proposed rule and arise out of the investigation reports or from other third-party recommendations.

Shearing Requirements

The BSEE regulations currently require that a BOP stack include a blind shear ram. A blind shear ram is designed to cut drill pipe in the well and shut in the well in an emergency well control situation. In order for a blind shear ram to shut in a well where drill pipe is across the BOP, it must be capable of shearing the drill pipe and there are known mechanical and design limitations that may prevent this from occurring. As demonstrated by the *Deepwater Horizon* incident, the failure of equipment to perform reliably can result in a major safety and/or environmental event.

Prior to the *Deepwater Horizon* incident, MMS commissioned the following research on shearing capabilities: Technical Assessment & Research (TAR) Project 383, *Performance of Deepwater BOP Equipment During Well-control Events;* TAR Project 408, *Development of a Blowout Intervention Method and Dynamic Kill Simulated for Blowouts Occurring Ultra-Deepwater;* TAR Project 431, *Evaluation of Secondary Intervention Methods in Well-control;* TAR Project 455, *Review of Shear Ram Capabilities;* and TAR Project 463, *Evaluation of Sheer Ram Capabilities.* This research can be found at *http://www.bsee.gov/Technology-and-Research/Technology-Assessment-Programs/Categories/Drilling/.* The research indicated that there was a large amount of uncertainty related to the shearing capability of existing BOPs. These reports documented that there were inconsistent and inadequate testing protocols used by manufacturers to demonstrate shearing capability, a failure to share shearing data that would allow for a better understanding of shearing capability, and a concern that not all operators and drilling contractors are aware of the limitations of the equipment they are using.

Following the *Deepwater Horizon* incident, the Agency received recommendations from multiple investigations and studies concerning the need for new and more rigorous requirements and technologies to ensure that drilling components can be severed and a well safely shut-in during an emergency. The BSEE is proposing a series of new requirements to address the gaps that were identified in these reports, incorporate recent industry standards, and assist in the adoption of improved technology through performance-based requirements.

Some of the limitations of current designs are well known. Industry acknowledges that BOP equipment would not shear drill collars, heavy weight drill pipe, or drill pipe tool joints. This inability to shear all of the components in the drill string can create significant complications in an emergency situation and increase the likelihood of a catastrophic event occurring. As the industry continues to develop more technically challenging resources, shearing and sealing become more difficult for several reasons, including:
—The improvements in drill pipe properties, particularly increased material strength and ductility, result in higher forces being required to shear the drill pipe in the future.
—Increased water depths, in combination with drilling fluid density and shut-in pressure, contribute to a BOP having to generate additional force to successfully shear.

The BSEE believes that the current testing protocols and verification procedures must be strengthened to ensure that the capabilities of shearing equipment are clearly understood and demonstrated. Furthermore, on a longer term basis, the overall performance of this equipment must improve to ensure that it can operate in an emergency situation and can successfully shear a drill stem. In this rule, BSEE is proposing to accomplish these objectives through the following:
—Require operators to assure that shearing capability for existing equipment complies with BSEE requirements related to shearing by performing tests and providing detailed results to a BSEE-approved verification organization. This organization would perform an independent engineering review of the test protocols and data and ensure that the testing would provide reasonable assurances that the equipment would perform as designed on drill pipe of specific mechanical and physical properties and under the operating conditions relevant to the particular well at which the equipment will be used. The BSEE expects that the independent engineering review would be based on recognized engineering practices. To become a BSEE-approved verification organization, organizations would need to submit documentation for BSEE approval describing the applicable qualifications and experience. This engineering review process would assist in developing more standardized testing protocols, increase data sharing within the industry, and provide information for future BSEE determinations of best available and safest technologies under section 21 of OSCLA, 43 U.S.C. 1347. The BSEE anticipates that industry would play an important role in this process by developing rigorous testing procedures and protocols for organizations that perform the testing.
—Require compliance with the latest industry standards contained in API Standard 53. In addition to these industry standards, BSEE would also include a requirement that operators use two shear rams in subsea BOP stacks. The use of double shear rams would increase the likelihood that a drill string can be sheared by ensuring that a shearable component is opposite a shear ram. In this proposed rulemaking, BSEE will not propose adopting the provision in API

Standard 53 that operators can ''opt out'' of this double shear ram requirement for moored rigs. If there are unique circumstances that prevent the use of two shear rams, operators would be able to apply for the use of alternative procedures or equipment under § 250.141.

—Require the use of BOP technology that provides for better shearing performance through the centering of the drill pipe in the shear rams. A number of investigations [1] have found that the shear rams did not completely cut the drill pipe in the *Deepwater Horizon.* This occurred because the drill pipe was not centered within the stack. The BSEE is aware of at least one BOP equipment manufacturer that currently has pipe centering technology available and proposes to require the use of pipe centering within 7 years after the publication of the final rule to encourage further technological development.

Equipment Reliability and Performance

Prior to the *Deepwater Horizon* incident, the industry's guidance document for the operation of BOPs was API RP 53—*Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells,* Third Edition, March 1, 1997 (Reaffirmed September 1, 2004). The BSEE currently incorporates only specific sections of this document in existing regulations, including sections related to maintenance, inspection, and accumulator systems. Following the *Deepwater Horizon* incident, industry recognized the need to enhance BOP guidance and concluded that it was necessary to completely rewrite API RP 53 and upgrade the document from an RP to a standard. The BSEE participated in the development of the industry standard and is proposing to incorporate the newly published standard into its regulations. Additionally, other key industry standards concerning this type of equipment would be incorporated by reference.

The BSEE concluded that incorporating new API Standard 53 provisions into its regulations would allow for better regulatory oversight and would ensure improved BOP design and operability. The BSEE believes that the incorporation of this document, and other key industry standards, such as ANSI/API Spec. 6A, ANSI/API Spec. 16A, API Spec. 16C, API Spec. 16D, ANSI/API Spec. 17D, and API Spec. Q1, would establish minimum design, manufacture, and performance baselines for this equipment and is essential to ensure the reliability and performance of this equipment. The BSEE anticipates that BOP equipment that meets these new requirements, along with several supplemental requirements (such as requiring blind-shear rams that incorporate improved pipe-centering designs), would perform in a more reliable manner.

The BSEE believes that the reliability of BOP-related equipment would also increase if its inspection, maintenance, and repair are performed by highly-trained personnel. Operators are currently required by BSEE regulations to ensure that all personnel are properly trained. The BSEE proposes to add requirements that specify that these personnel be qualified and trained pursuant to original equipment manufacturer (OEM) recommendations, unless otherwise specified by BSEE. The BSEE encourages industry to develop standards and certification programs for these personnel.

Third-Party Verification

Regulatory oversight of the lifecycle of BOP equipment, ranging from design, installation, inspection, testing, maintenance, and repair, presents a variety of logistical and technical challenges, especially because the equipment might be used at multiple locations. In several sections of the proposed regulations, BSEE would require third-party verification of the design, maintenance, inspection, testing, and repair of BOP systems and equipment by a BSEE-approved entity. We believe that the use of third-party verification organizations would help BSEE ensure that these systems are designed and maintained during their entire service life to minimize risk. For subsea BOPs or BOPs used in HPHT applications, we are proposing that BSEE-approved verification organizations submit reports verifying compliance with these new requirements. This verification would provide BSEE with reasonable assurance that the equipment is fit for service as intended.

The BSEE is also proposing an additional qualification and verification process for BOP(s) and related equipment used in HPHT wells. The verification must be specific to the conditions of the particular well at which the BOP(s) will be used. This verification process is needed because there are currently no engineering standards for the design, fabrication, and testing of equipment used in HPHT conditions. The use of a BSEE-approved verification organization would provide an additional layer of review and verification during the development and operation of the equipment. It would be the responsibility of the operator to clearly demonstrate to the BSEE-approved verification organization and BSEE that the equipment was designed for the HPHT conditions specific to the well, and will perform in a reliable manner during its service life under those conditions. To become a BSEE-approved verification organization, the organization would have to submit documentation for approval describing the organization's applicable qualifications and experience.

Failure Reporting/Near-Miss Reporting

Several of the standards that BSEE proposes to incorporate by reference contain failure reporting processes that ensure that operators share information with OEMs related to the performance of their equipment. This sharing of information makes it possible for the OEMs to notify users of any safety issues that arise. In 2009, the industry provided the MMS with a BOP reliability study that specifically noted the importance of ANSI/API Spec. 16A, Annex F, and referred to this requirement as ''an excellent practice that assists manufacturers in identifying problems that occur in the operation and maintenance of their projects.'' The BSEE agrees with this statement and is including this requirement in the proposed regulations.

Because the same equipment designs are often used by multiple operators, ensuring the timely reporting of this type of data can play an important role in preventing future incidents. The need for a formalized process for disseminating information to the industry was clearly demonstrated following the December 2012 failures of certain bolts used in BOPs and wellhead connectors in the Gulf of Mexico (GOM). Subsequent investigations revealed that although these failures had occurred over a period of years, most of the industry was not aware of the safety issues. The BSEE is proposing that the operators report any significant problems with BOP or well-control equipment to BSEE to ensure that this information can be provided in a timely manner to OCS operators and the international community. In the long term, BSEE would continue to encourage industry to develop a comprehensive and formalized method of collecting, analyzing, and disseminating failure data involving critical equipment.

Safe Drilling Practices

The proposed regulations include new requirements related to the maintenance of safe drilling margins

[1] *See* DOI JIT investigation recommendation, D6.

consistent with the recommendations arising out of *Deepwater Horizon* investigations. The BSEE also proposes to add requirements related to liners and other downhole equipment. We believe that these requirements would help to reduce the likelihood of a major well-control event occurring and ensure the overall integrity of the well design.

The proposed rule would require that operators have the capability to monitor deepwater and HPHT drilling operations from the shore and in real time. This would allow operators to anticipate and identify issues in a timely manner and to utilize onshore resources to assist in addressing critical issues. It would allow BSEE greater visibility of operations so BSEE may focus on specific critical operations for additional oversight.

The BSEE also proposes a requirement that designated operators report leaks associated with BOP control systems on the daily report, in the WAR, and directly to the District Manager. This requirement would ensure that the agency is made aware of any leaks and may determine if agency action is appropriate.

The proposed regulation would include requirements concerning ROV operations, including the adoption of API RP 17H to standardize ROV hot stab activities. An ROV hot stab is a high pressure subsea connector used to connect the ROV into the BOP system. An ROV hot stab is basically comprised of two parts:

—A valve; and
—A tool that connects onto the valve and controls the valve.

The valve is usually placed on the subsea BOP stack panel, and is accessible for an ROV to insert the tool and activate certain functions on the BOP.

BOP Testing

In response to public input related to the value of pressure testing in predicting future performance of a BOP and industry concerns about the operational safety issues associated with performing these tests, BSEE proposes to modify the BOP testing frequency for workover and decommissioning operations. The BSEE proposes to change the current 7 day BOP testing interval for workover (current § 250.617(b)) and decommissioning (current § 250.1707(b)) operations to 14 days, which is consistent with the testing frequency requirements (reference current § 250.447(b) and 250.517(a)) for drilling and completion operations. Some drilling, completion, workover, and decommissioning operations use the same rigs and BOP systems; therefore, to ensure consistency among different operations involving the same equipment, BSEE proposes to harmonize the requirements for that type of equipment. Harmonizing the testing frequency would streamline the BOP function-testing criteria and increase safety by reducing repetition of operations, such as pulling out of the hole and running in the hole, that pose operational safety issues, therefore limiting the exposure of potential risks to offshore personnel. This may also have a positive effect on overall equipment durability and reliability.

A benefit of this provision would be a cost saving to industry. We estimated the total cost savings to industry from this provision to be $150,000,000 per year (see the economic analysis for more detailed information). Based upon existing available data and the timeframes of the economic analysis, the cost savings benefits of the proposed rule would result in benefits greater than the identified quantitative costs of the rule. The BSEE is requesting comments on whether the proposed BOP testing interval should be 7 days, 14 days (as proposed), or 21 days for all types of operations including drilling, completions, workovers, and decommissioning. The BSEE is also requesting comments on the specific cost implications of each testing interval to further its consideration of the issue. For more information on the costs and benefits of the proposed rule, refer to the economic analysis.

In addition to cost savings benefits, BSEE's economic analysis also considers benefits from potential reductions in oil spills and reduced fatalities. The BSEE is requiring additional measures (*e.g.* real-time monitoring and increased maintenance) that help ensure the functionality and operability of the BOP system and, therefore, will reduce the risks of spills and fatalities.

The BSEE is also soliciting comments on the use of pressure and functional tests during drilling operations to verify performance, the adequacy of current and proposed testing requirements, and the identification of risks associated with increasing or decreasing the testing frequency.

II. Organization of Subpart G

The BSEE determined that the most effective way to communicate consistent requirements for BOPs across all well operations (drilling, completion, workover, and decommissioning) is to consolidate those common requirements in one location. The current regulations repeat similar BOP requirements in multiple locations throughout 30 CFR part 250. The BSEE is proposing to consolidate these requirements into Subpart G, which is currently reserved. This would allow better flexibility, efficiency, and consistency in future rulemaking. The proposed rule would structure proposed Subpart G—Well Operations and Equipment, under the following undesignated headings:

—GENERAL REQUIREMENTS
—RIG REQUIREMENTS
—WELL OPERATIONS
—BLOWOUT PREVENTER (BOP) SYSTEM REQUIREMENTS
—RECORDS AND REPORTING

The sections contained within this new subpart would apply to all drilling, completion, workover, and decommissioning activities, unless explicitly stated otherwise.

III. Effective Date of a Final Rule

The BSEE understands that operators may need time to comply with certain requirements proposed in this rule. The BSEE is taking into consideration the amount of time needed to meet the requirements for the installation of double shear rams and new certification requirements. Based on information provided by industry, all new drilling rigs are already being built, pursuant to the same industry standards BSEE now proposes to adopt (including API Standard 53), and many have already been retrofitted to comply with these industry standards. Furthermore, most already comply with recognized engineering practices and OEM requirements related to repair and training. The BSEE evaluated the proposed requirements in this proposed rule and seeks to set reasonable effective dates for those requirements based on information gained during, among other activities, interaction with stakeholders, involvement with development of industry standards, and evaluation of current technology. The BSEE proposes an effective date of 3 months following publication of the final rule. Operators would be required to demonstrate compliance with most of the proposed requirements at that time, with the exception of the following more extended timeframes:

—Operators would be required to comply with the real-time monitoring requirements within 3 years from the publication of the final rule.
—Operators would be required to install double shear rams on subsea BOPs and on surface BOPs on floating facilities within 5 years from the publication of the final rule.
—Operators would be required to install shear rams that center drill pipe during shearing operations within 7

years from the publication of the final rule.

The BSEE is soliciting comments about the proposed compliance dates for the requirements in this proposed rule to ensure the dates are appropriate. The BSEE is specifically soliciting comments on whether the 3-month, 3-year, 5-year, and 7-year compliance dates are appropriate and achievable. The BSEE is also specifically soliciting comments on whether the proposed requirements can be met sooner than the proposed compliance dates (*e.g.,* 5 years after publication of the final rule for centering drill pipe), and the anticipated costs for meeting these proposed compliance dates. Please provide justification for your responses.

Note that BSEE still retains the discretion under § 250.141 to authorize alternate procedures or equipment that provide an equivalent level of safety and environmental protection.

IV. Future Plans for Subpart G

In future rulemaking, BSEE intends to include additional regulatory requirements for operations and equipment in Subpart G, such as:

—Well-control planning, procedures, training, and certification;
—Major rig equipment;
—Certification requirements for personnel servicing critical equipment;
—Choke and kill systems;
—Mud gas separators;
—Wellbore fluid safety practices, testing, and monitoring;
—Diverter systems with subsea BOPs; and
—Coiled tubing, snubbing, and wireline units.

The BSEE is also researching other topics that would be appropriate for inclusion into this new subpart in future rulemakings.

V. Section-By-Section Discussion

Subpart A—General

What does this part do? (§ 250.102)

This section would be revised to add references for Subpart G to (b)(1), (11), (12), and (13) and also add new paragraph (b)(19) to the table. This would be added so the public will know that they can find requirements about well operations and equipment in proposed Subpart G.

What must I do to protect health, safety, property, and the environment? (§ 250.107)

Paragraph (a) of this section would be revised to include a general performance-based requirement that operators utilize recognized engineering practices that reduce risks to the lowest level practicable during activities covered by the regulations and conduct all activities pursuant to the applicable lease, plan, or permit terms or conditions of approval. Recognized engineering practices may be drawn from established codes, industry standards, published peer-reviewed technical reports or industry recommended practices, and similar documents applicable to engineering, design, fabrication, installation, operation, inspection, repair, and maintenance activities. This risk reduction objective is used in other regulatory programs and is consistent with BSEE's goal of taking a more risk-based approach in its regulations. This risk reduction principle has also been included in a recently published industry document (API Bulletin 97) which addresses drilling, completion, and workover activities.

Proposed paragraph (e) would be added to clarify BSEE's authority to issue orders when necessary to protect health, safety, property, or the environment. The first sentence authorizes BSEE to issue orders to ensure compliance with the regulations. The second sentence clarifies that BSEE may order that operations of a component or facility be shut-in because of a threat of serious, irreparable, or immediate harm to health, safety, property, or the environment posed by those operations or because the operations violate law, including a regulation, order, or provision of a lease, plan, or permit.

Service fees. (§ 250.125)

This table in this section would be revised to reflect the correct citation for payment of the service fee relating to DWOPs.

Documents incorporated by reference. (§ 250.198)

This section would be revised to update citations of currently incorporated documents and to incorporate new documents. Changes to this section would include:

—Revising paragraph (h)(51) to update cross-references to the sections incorporating API RP 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs);
—Removing the incorporation of API RP 53 in paragraph (h)(63) and in its place incorporating new API Standard 53, Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition (with the exception of the opt-out provision);
—Revising paragraph (h)(68) to update cross-references to the sections incorporating API Spec. Q1, Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry;
—Revising paragraph (h)(70) to update cross-references to the sections incorporating ANSI/API Spec. 6A, Specification for Wellhead and Christmas Tree Equipment;
—Adding new paragraph (h)(89) to incorporate ANSI/API Spec. 11D1, Packers and Bridge Plugs;
—Adding new paragraph (h)(90) to incorporate ANSI/API Spec. 16A, Specification for Drill-through Equipment;
—Adding new paragraph (h)(91) to incorporate API Spec. 16C, Specification for Choke and Kill Systems;
—Adding new paragraph (h)(92) to incorporate API Spec. 16D, Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment;
—Adding new paragraph (h)(93) to incorporate ANSI/API Spec. 17D, Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment;
—Adding new paragraph (h)(94) to incorporate ANSI/API RP 17H, Remotely Operated Vehicle Interfaces on Subsea Production Systems.

Paperwork Reduction Act statements—information collection. (§ 250.199)

This section would be revised by:

—Changing all the OMB Control Numbers from the 1010 numbering system to BSEE's new 1014 numbering system;
—Rewording for plain language the reasons that BSEE collects the information and how it is used; and
—Adding paragraphs for APDs, Application for Permit to Modify (APM), and Subpart G in the table to identify the basis for the information collection.

Subpart B—Plans and Information

What must the Deepwater Operations Plan (DWOP) contain? (§ 250.292)

The proposed rule would re-designate existing paragraph (p) to (q) and add a new paragraph (p). Proposed new paragraph (p) would specify FSHR requirements within the DWOP. The FSHRs are used in combination with FPSOs. The use of FPSOs is relatively new to the GOM. There is only one FPSO currently operating in the GOM; however, the use of FPSOs is expected to increase in the next few years.

Currently, BSEE approves the use of FPSOs and associated FSHRs through the DWOP process, but has no regulations specifically addressing the use of FSHRs. Proposed paragraph (p) would outline what BSEE requires in a DWOP that proposes the use of FSHRs. The new requirements would include submission of the following:

—Detailed descriptions and drawings of the FSHR buoy and tether system;
—Information on the design, fabrication, and installation of the FSHR buoy and tether system, including pressure ratings, fatigue life, and yield strengths;
—A description of how the operator met the design requirements, load cases, and allowable stresses for each load case according to API RP 2RD, RP for Design of Risers for FPSs and TLPs;
—Detailed information regarding the tether system used to connect the FSHR to a buoyancy air can;
—Descriptions of the monitoring system and a monitoring plan to monitor the pipeline FSHR and tether for fatigue, stress, and any other abnormal condition (*e.g.,* corrosion) that may negatively impact the riser or tether; and
—Documentation that the tether system and connection accessories for the pipeline FSHR have been certified by an approved classification society or equivalent and verified by the Certified Verification Agent (CVA) as required in current Subpart I and clarified in BSEE NTL 2007–G14, *Pipeline Risers Subject to the Platform Verification Program.*

Subpart D—Oil and Gas Drilling Operations

General Requirements. (§ 250.400)

The proposed rule, would revise this entire section including the section heading. The current section entitled, *Who is subject to the requirements of this subpart?* is not necessary because the subject matter is sufficiently covered under § 250.146, which states that lessees, operators, and the person actually performing the activity to which a requirement applies are jointly and severally responsible for complying with the regulations.

The new proposed language would require drilling operations to be done in a safe manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the OCS, including any mineral deposits (in areas leased and not leased), the National security or defense, or the marine, coastal, or human environment. The new section would also clarify that for drilling operations, the operator would need to follow the requirements of this subpart and the applicable requirements of proposed Subpart G.

What must I do to keep wells under control? (§ 250.401)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.703.

When and how must I secure a well? (§ 250.402)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.720.

What drilling unit movements must I report? (§ 250.403)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.712.

What additional safety measures must I take when I conduct drilling operations on a platform that has producing wells or has other hydrocarbon flow? (§ 250.406)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.723.

What information must I submit with my application? (§ 250.411)

This section would be revised by separating the diverter and BOP descriptions in the table containing regulatory cross-references for descriptions of APD information, and updating the cross-references to include proposed Subpart G.

What must my description of well drilling design criteria address? (§ 250.413)

This section would revise paragraph (g) to include the maximum ECD on the pore pressure/fracture gradient plot. The ECD is the effective density exerted by a circulating fluid against the formation that takes into account the pressure drop in the annulus. The ECD is an important parameter in avoiding kicks and losses, particularly in wells that have a narrow window between the fracture gradient and pore pressure. This information is necessary for proper well drilling design and for BSEE to better review the drilling program.

What must my drilling prognosis include? (§ 250.414)

This section would revise paragraphs (c), (h), and (i) and add new paragraphs (j) and (k).

Paragraph (c) of this section would be revised to better define the safe drilling margin requirements. The planned safe drilling margins would be required to be between the proposed drilling fluid weights and the estimated pore pressures and the lesser of estimated fracture gradients or casing shoe pressure integrity test. The safe drilling margins would also have to meet the following conditions:

—Static downhole mud weight must be greater than estimated pore pressure;
—Static downhole mud weight must be a minimum of one-half pound per gallon below the lesser of the casing shoe pressure integrity test or the lowest estimated fracture gradient;
—The ECD must be below the lesser of the casing shoe pressure integrity test or the lowest estimated fracture gradient;
—When determining the pore pressure and lowest estimated fracture gradient for a specific interval, related hole behavior must be considered (*e.g.,* pressures, influx/loss of fluids, and fluid types).

Changes to better define safe drilling margins are partially based on the information revealed during investigations of the *Deepwater Horizon* incident.[2] Safe drilling margins are used to determine the downhole fluid program and ensure fluid densities are capable of controlling the estimated pore pressure and formation fluids while not fracturing the formations. With clearer requirements for safe drilling margins, operators would be able to better understand BSEE requirements and design fluid programs accordingly.

Paragraphs (h) and (i) would be revised with only minor wording changes.

New paragraph (j) would be added to require that the drilling prognosis include the type of wellhead and liner hanger systems to be installed and a descriptive schematic. The descriptive schematic would include, among other information, pressure ratings, dimensions, valves, load shoulders, and locking mechanism, if applicable. This information would assist BSEE in its review of the APD, and assist staff in ensuring that the wellhead and liner hanger systems are adequate for the proposed use.

New paragraph (k) would be added to require submittal of any additional information required by the District Manager.

What must my casing and cementing programs include? (§ 250.415)

Paragraph (a) of this section would be revised to include casing information for all sections of each casing interval. Operators would also need to include

[2] *See* DOI JIT investigation recommendation, A3.

bit depths (including measured and true vertical depth (TVD)), and locations of any installed rupture disks and indicate either the collapse or burst ratings. Requiring this information for all sections for each casing interval would make design calculations and submittals more accurate and provide a complete representation of the well.

What must I include in the diverter description? (§ 250.416)

This heading and section would be revised to remove the BOP descriptions and leave the diverter descriptions. The BOP descriptions would be moved to new Subpart G in proposed §§ 250.730, 250.731, and 250.732. The diverter requirements would remain unchanged.

What must I provide if I plan to use a mobile offshore drilling unit (MODU)? (§ 250.417)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.713.

What additional information must I submit with my APD? (§ 250.418)

Paragraph (g) of this section would be revised to require operators to seek approval for plans to wash out or displace cement to facilitate casing removal upon well abandonment. The request would need to include a description of how far below the mudline the operator proposes to displace cement and how the operator will visually monitor returns. This proposed change would provide information that would assist BSEE in its review of the APD.

What well casing and cementing requirements must I meet? (§ 250.420)

The introductory language in this section would be revised to require that applicable casing and cementing requirements in proposed Subpart G must also be followed.

Existing paragraph (a)(6) would be renumbered as paragraph (a)(7). New paragraph (a)(6) would be added to require adequate centralization to help ensure proper cementation. Multiple *Deepwater Horizon* investigations discussed the use of centralizers, which are devices that maintain the casing or liner in the center of the wellbore to help ensure efficient placement of cement around the casing string. If an operator cements casing off-center, the wellbore may not be properly sealed. New paragraph (b)(4) would be added to specify 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. This addition is necessary to ensure the casing is suitable for the well conditions and for BSEE to have the most up-to-date wellbore information.

Paragraph (c) would be renumbered and revised by adding a new paragraph (c)(2). New paragraph (c)(2) would require the use of a weighted fluid to maintain an overbalanced hydrostatic pressure during the cement setting time, except when cementing casings or liners in riserless hole sections. This proposed change would enhance wellbore stability during cementing.

The use of a weighted fluid is particularly important because most well-control events occur due to inadequately weighted fluids in the hole, as well as inadequate volume of fluid to hold back the pressures in the well. A weighted fluid has a greater density than seawater. As the density of the weighted fluid increases, it exerts a greater hydrostatic pressure, thereby minimizing the potential for the well to flow.

What are the casing and cementing requirements by type of casing string? (§ 250.421)

Paragraph (b) of the table in this section would be revised to specify that 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, even if it is before the planned casing point. This proposed change would ensure that conductor casing is not placed across a hydrocarbon zone.

Paragraph (f) of the table in this section would be revised to disallow the use of liners as conductor casing. When a liner is used as conductor casing, a portion of the drive pipe is exposed to wellbore pressure, and BSEE does not accept drive pipe as a pressure-rated component. By prohibiting the use of liners as conductor casing, BSEE would ensure that the drive pipe is not exposed to wellbore pressures.

What are the requirements for casing and liner installation? (§ 250.423)

This section would be revised as follows:

—Change the heading to more accurately reflect corresponding changes within the section.
—Remove the pressure testing and negative pressure testing requirements. The pressure testing requirements would be found in proposed § 250.721.
—Add information to clarify that liner latching mechanisms, if applicable, would need to be engaged upon successfully installing and cementing the casing string or liner.

This last addition would reinforce the importance that liners are properly secured in place to ensure wellbore integrity. The requirements for latching and lockdown mechanisms were also a topic of discussion in the DOI JIT *Deepwater Horizon* investigation.

What are the requirements for prolonged drilling operations? (§ 250.424)

This section would be removed and reserved. The content of this section would be moved to in proposed § 250.722.

What are the requirements for pressure testing liners? (§ 250.425)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.721.

What are the recordkeeping requirements for casing and liner pressure tests? (§ 250.426)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.746.

What are the requirements for pressure integrity tests? (§ 250.427)

Paragraph (b) would be revised to clarify that operators must maintain the drilling margins as described in § 250.414.

What must I do in certain cementing and casing situations? (§ 250.428)

Paragraph (b) of the table in this section would be revised to require District Manager approval for hole interval drilling depth changes greater than 100 feet TVD, and submittal of a professional engineer (PE) certification, certifying that the PE reviewed and approved the proposed changes. This requirement would assist BSEE in verifying the actual well conditions. This new requirement would also ensure proper PE review of associated changes.

Paragraph (c) of the table in this section would be revised to clarify requirements concerning what actions must be taken if there is an indication of an inadequate cement job. There are many indicators of an inadequate cement job. These include lost returns, no returns to the mudline or failure to reach the expected height for the specific cement job, cement channeling, abnormal pressures, or failure of equipment. If any of these indicators, or others, are encountered during the cement job, then action must be taken to ensure the cement job is adequate. Such actions may include running a temperature survey, running a cement evaluation log (such as an ultrasonic or equivalent bond log), or a combination of these or other techniques to check cement integrity by verifying the top of cement, density, condition, bond, etc. If the cement job is determined to be adequate, the results of the cement job determination would be submitted to the District Manager in the WAR.

Paragraph (d) of the table in this section would be revised to clarify that if an operator has an inadequate cement job, the District Manager would have to review and approve all proposed remedial actions, unless immediate actions must be taken to ensure the safety of the crew or to prevent a well-control event. If the operator needs to take immediate action, a description would be required to be submitted to the District Manager once the action is completed. The paragraph would also clarify that any changes to the well program would require PE certification and would need to meet any other requirements imposed by the District Manager.

New paragraph (k) would be added to the table in this section and would add clarification concerning the use of valves on drive pipes during cementing operations for the conductor casing, surface casing, or liner, and require the following to assist BSEE in assessing the structural integrity of the well:

—The operator would include a description in the APD of the plan to use a valve that includes a schematic of the valve and height above the water line.
—The valve would be remotely operated and full opening with visual observation while taking returns.
—The person in charge of observing returns would be in communication with the drill floor.
—The operator would record in the daily report and in the WAR if cement returns were observed; and
—If cement returns were not observed, the operator would have to contact the District Manager and obtain approval of proposed plans to locate the top of cement, before continuing with operations.

These proposed additions in paragraph (k) would help BSEE assess the well's structural integrity and verify cement suitability to the mudline.

The overall changes to this section would help BSEE assess actual well operations and conditions, and also would help ensure proper design with additional PE review.

What are the general requirements for BOP systems and system components? (§ 250.440)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.730.

What are the requirements for a surface BOP stack? (§ 250.441)

This section would be removed and reserved. The content of this section would be moved to proposed §§ 250.733 and 250.735.

What are the requirements for a subsea BOP system? (§ 250.442)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.734.

What associated systems and related equipment must all BOP systems include? (§ 250.443)

This section would be removed and reserved. The content of this section would be moved to proposed §§ 250.733, 250.734, and 250.735.

What are the choke manifold requirements? (§ 250.444)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.736.

What are the requirements for kelly valves, inside BOPs, and drill-string safety valves? (§ 250.445)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.736.

What are the BOP maintenance and inspection requirements? (§ 250.446)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.739.

When must I pressure test the BOP system? (§ 250.447)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.737.

What are the BOP pressure tests requirements? (§ 250.448)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.737.

What additional BOP testing requirements must I meet? (§ 250.449)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.737.

What are the recordkeeping requirements for BOP tests? (§ 250.450)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.746.

What must I do in certain situations involving BOP equipment or systems? (§ 250.451)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.738.

What safe practices must the drilling fluid program follow? (§ 250.456)

This section would remove paragraph (j) and re-designate the other paragraphs. The content of current paragraph (j) would be moved to proposed § 250.720 to clarify that this requirement applies to drilling, workover, completion, and abandonment operations.

What are the source control and containment requirements? (§ 250.462)

This section and heading would be entirely revised. The existing content of this section entitled, *What are the requirements for well-control drills?* would be moved to proposed §§ 250.710 and 250.711.

This proposed new section would add requirements for the operator to demonstrate the ability to control or contain a blowout event at the sea floor. This section would apply to operations using a subsea BOP or a surface BOP on a floating facility.

Paragraph (a) would require the operator to determine its source control and containment capabilities by evaluating the performance of the well design to determine if a full shut-in can be achieved without reservoir fluids broaching the sea floor. Based on this evaluation, if the well can only be partially shut-in, then the operator would be required to establish the ability to flow and capture any residual fluids to a surface production and storage system.

Paragraph (b) would require that operators have access to, and the ability to deploy, Source Control and Containment Equipment (SCCE) necessary to regain control of the well. The SCCE means the capping stack, cap and flow system, containment dome, and/or other subsea and surface devices, equipment, and vessels whose collective purpose is to control a spill source and stop the flow of fluids into the environment or to contain fluids escaping into the environment. This equipment would need to include, but not be limited to:

—Subsea containment and capture equipment, including containment domes and capping stacks;
—Subsea utility equipment, including hydraulic power, hydrate control, and dispersant injection equipment;
—Riser systems;

—ROVs;

—Capture vessels;

—Support vessels; and

—Storage facilities.

Paragraph (c) would require submittal of a description of the source control and containment capabilities before BSEE would approve an APD. The submittal to the Regional Supervisor would need to include the following:

—The source control and containment capabilities for controlling and containing a blowout event at the seafloor,

—A discussion of the determination required by paragraph (a), and

—Information showing that the operator has access to, and the ability to deploy, all equipment necessary to regain control of the well.

Paragraph (d) would require that operators contact the District Manager and Regional Supervisor for reevaluation of the source control and containment capabilities if there are any well design changes or if any of the approved SCCE is out of service.

Paragraph (e) would outline the maintenance, inspection, and testing requirements of certain identified containment equipment as follows:

Equipment	Requirements	Additional information
(1) Capping stacks	(i) Function test all pressure holding critical components on a quarterly frequency (not to exceed 104 days),	Pressure holding critical components are those components that will experience wellbore pressure during a shut-in after being functioned.
	(ii) Pressure test pressure holding critical components on a bi-annual basis, but not later than 210 days from the last pressure test. All pressure testing must be witnessed by BSEE and a BSEE-approved verification organization,	Pressure holding critical components are those components that will experience wellbore pressure during a shut-in. These components include, but are not limited to: all blind rams, wellhead connectors, and outlet valves.
	(iii) Notify BSEE at least 21 days prior to commencing any pressure testing.	
(2) Production safety systems used for flow and capture operations.	(i) Meet or exceed the requirements set forth in 30 CFR 250.800 through 250.808, Subpart H.	
	(ii) Have all equipment unique to containment operations available for inspection at all times.	
(3) Subsea utility equipment	Have all equipment unique to containment operations available for inspection at all times,	Subsea utility equipment includes, but is not limited to: hydraulic power sources, debris removal, hydrate control equipment, and dispersant injection equipment.

All of these changes in this section are necessary for BSEE to properly assess an operator's ability to access and deploy appropriate equipment sufficient to control and contain a blowout subsea. The *Deepwater Horizon* incident demonstrated a need for the capabilities to control and contain subsea blowouts. Following the *Deepwater Horizon* incident, operators did not resume certain drilling operations on the OCS until successfully demonstrating their ability to control and contain a subsea blowout. Industry quickly developed the capabilities and equipment, and satisfactorily demonstrated to BSEE the equipment capabilities to ensure subsea blowout control and containment.

The BSEE is considering applying the requirements of this section to other operations besides those that use a subsea BOP or surface BOP on a floating facility. Specifically, BSEE is soliciting comments on whether the source control and containment requirements should be applicable to wells drilled in shallow water. Please provide reasons for your position. If your comment addresses anticipated costs associated with such a requirement, please provide any available supporting data.

When must I submit an Application for Permit to Modify (APM) or an End of Operations Report to BSEE? (§ 250.465)

Paragraph (b)(3) would be revised to clarify that if there is a:

—Revision to the drilling plan;

—Major drilling equipment change; or

—Plugback,

operators would have to submit an EOR, Form BSEE–0125, as required in proposed § 250.744, within 30 days after completing the work. This would help ensure that BSEE has the current well information.

What records must I keep? (§ 250.466)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.740.

How long must I keep records? (§ 250.467)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.741.

What well records am I required to submit? (§ 250.468)

This section would be removed and reserved. The content of this section would be moved to proposed §§ 250.742 and 250.743.

What other well records could I be required to submit? (§ 250.469)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.745.

Subpart E—Oil and Gas Well-Completion Operations

General requirements. (§ 250.500)

This section would be revised to add a requirement to follow the applicable requirements of new Subpart G in addition to Subpart E. With the development of new Subpart G, BSEE would consolidate similar requirements regarding drilling, workover, completion, and decommissioning activities into a separate subpart. It is BSEE's intention to include additional regulations regarding similar operations and equipment in the new Subpart G in future regulations.

This section would also be revised to replace the word "shall" with "must." This change would clarify that the provision is mandatory.

Equipment movement. (§ 250.502)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.723.

Crew instructions. (§ 250.506)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.710.

Well-control fluids, equipment, and operations. (§ 250.514)

Paragraph (d) would be removed and its content would be moved to proposed § 250.720.

What BOP information must I submit? (§ 250.515)

This section would be removed and reserved. The content of this section would be moved to proposed §§ 250.731 and 250.732.

Blowout prevention equipment. (§ 250.516)

This section would be removed and reserved. The content of this section would be moved to proposed §§ 250.730, 250.733, 250.734, 250.735, and 250.736.

Blowout preventer system tests, inspections, and maintenance. (§ 250.517)

This section would be removed and reserved. The content of this section would be moved to proposed §§ 250.711, 250.737, 250.738, 250.739, and 250.746.

Tubing and wellhead equipment. (§ 250.518)

This section would be revised by removing paragraph (b), redesignating the rest of the paragraphs to reflect the removal of paragraph (b), and adding new paragraphs (e) and (f) to clarify packer and bridge plug requirements. The content of paragraph (b) would be moved to proposed § 250.722 and would clarify that these requirements apply to drilling, workover, completion, and abandonment operations.

New paragraph (e) would add packer and bridge plug requirements including:

—Adherence to newly incorporated API Spec. 11D1, *Packers and Bridge Plugs;*
—Production packer setting depth to allow for a sufficient column of weighted fluid for hydrostatic control of the well; and
—Production packer setting depth criteria.

New paragraph (f) would require, in your APM, a description and calculations of how the production packer setting depth was determined.

Subpart F—Oil and Gas Well-Workover Operations

General requirements. (§ 250.600)

This section would be revised to add the requirement to follow the applicable provisions of new Subpart G in addition to Subpart F. With the new development of Subpart G, BSEE is consolidating similar requirements regarding drilling, workover, completion, and decommissioning activities. It is BSEE's intention to include additional regulations regarding similar operations and equipment in new Subpart G in future regulations.

This section would also be revised to replace the word ''shall'' with ''must.'' This change would clarify that the provision is mandatory.

Equipment movement. (§ 250.602)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.723.

Crew instructions. (§ 250.606)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.710.

Well-control fluids, equipment, and operations. (§ 250.614)

Paragraph (d) would be removed and its content would be moved to proposed § 250.720.

What BOP information must I submit? (§ 250.615)

This section would be removed and reserved. The content of this section would be moved to proposed §§ 250.731 and 250.732.

Coiled tubing and snubbing operations. (§ 250.616)

The section would be revised by renaming the section heading to ''Coiled tubing and snubbing operations,'' removing paragraphs (a) through (e), and re-designating paragraphs (f) through (h) as (a) through (c). The content of existing paragraphs (a) through (e) would be moved to proposed §§ 250.730 and 250.733 through 250.736.

Blowout preventer system testing, records, and drills. (§ 250.617)

This section would be removed and reserved. The content of this section would be moved to proposed §§ 250.711, 250.737, and 250.746.

What are my BOP inspection and maintenance requirements? (§ 250.618)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.739.

Tubing and wellhead equipment. (§ 250.619)

This section would be revised by removing paragraph (b), redesignating the rest of the paragraphs to reflect the removal of paragraph (b), and adding new paragraphs (e) and (f) to clarify packer and bridge plug requirements. The content of paragraph (b) would be moved to proposed § 250.722.

New paragraph (e) would add packer and bridge plug requirements for when operators pull and reinstall packers and bridge plugs, including:

—Adherence to newly incorporated API Spec. 11D1, *Packers and Bridge Plugs;*
—Production packer setting depth to allow for a sufficient column of weighted fluid for hydrostatic control of the well; and
—Production packer setting depth criteria.

This new paragraph would codify existing BSEE policy to ensure consistent permitting. The incorporation of API Spec. 11D1 would enhance packer and bridge plug reinstallation and ensure conformance to industry specifications and good industry practices not previously covered in BSEE regulations.

New paragraph (f) would require, in the APM, a description and calculation of how the production packer setting depth was determined.

Subpart G—Well Operations and Equipment

This part of the section-by-section will not address any regulatory provisions that BSEE proposes to move without change from existing subparts to the new subpart G because the proposed moves in regulatory text are discussed above. However, this portion of the section-by-section will explain existing language that BSEE proposes to revise or add as new provisions.

General Requirements

What operations and equipment does this subpart cover? (§ 250.700)

This proposed section explains that new Subpart G would apply to drilling, completion, workover, and decommissioning activities and equipment. New Subpart G would contain common requirements for these activities. Every section in Subpart G would be applicable to drilling, completion, workover, and decommissioning activities, unless explicitly stated otherwise.

May I use alternate procedures or equipment during operations? (§ 250.701)

Content in this proposed section is similar to existing § 250.408. This proposed section would explain that operators may seek approval to use alternate procedures or equipment following the process set forth in § 250.141. This section would also specify that the proposed alternate procedures and equipment must be discussed in the APD or APM. This section would make the information in

§ 250.408 applicable to all operations covered by this subpart.

May I obtain departures from these requirements? (§ 250.702)

The content of this proposed section is similar to existing § 250.409. This proposed section would explain that operators may request departures from the regulations in this subpart by using the procedure set forth in § 250.142. Also, this section would clarify what would be required for the departure request. Another addition to this section would require that the departure request be discussed in the APD or APM.

What must I do to keep wells under control? (§ 250.703)

The content of this proposed section was moved from existing § 250.401. Language in this section would be revised to ensure applicability to all operations covered under this subpart, and to require the use of equipment that is designed, tested, and rated for the most extreme conditions to which the equipment will be exposed while in service. This section would also require that personnel be trained according to the provisions of Subparts O and S. These subparts outline minimum training requirements. The BSEE expects personnel performing operations to be trained and knowledgeable of their required actions and duties.

Rig Requirements

What instructions must be given to personnel engaged in well operations? (§ 250.710)

The content of this proposed section was moved from existing §§ 250.462, 250.506, and 250.606. This section would require personnel engaged in well operations to be instructed in safety requirements, possible hazards, and general safety considerations as required by Subpart S, prior to engaging in operations.

This proposed section would clarify that the well-control plan must contain instructions for personnel about the use of each well-control component of the BOP system, and include procedures for shearing pipe and sealing the wellbore in the event of a well control or emergency situation before maximum anticipated surface pressure (MASP) conditions are reached. These changes would establish better proficiency for personnel using well-control equipment.

What are the requirements for well-control drills? (§ 250.711)

The content of this proposed section was moved from existing §§ 250.462, 250.517(f), 250.617(c), and 250.1707(c). This section would add minor revisions to make the requirement applicable to all drilling, completion, workover, and decommissioning operations covered under this subpart. This section would also clarify that the same drill may not be repeated consecutively. These proposed changes would establish better proficiency for personnel using well-control equipment.

What rig unit movements must I report? (§ 250.712)

The content of this proposed section was moved from existing § 250.403 with the following revisions and additions:

Paragraph (a) would be revised to add rig movement reporting requirements for all rig units moving on and off locations. Rig units include MODUs, platform rigs, snubbing units, wire-line units used for non-routine operations, and coiled tubing units. This paragraph would make rig movement reporting requirements applicable to all rigs conducting operations covered under proposed Subpart G. The deadline for notifying the District Manager about rig movements, using the Rig Movement Notification Report (Form BSEE–0144), would increase from 24 to 72 hours. This proposed change would allow BSEE to better anticipate upcoming operations and coordinate applicable permitting.

Paragraph (a)(2) would be revised to clarify that if operators anticipate moving off location less than 72 hours after initially moving onto location, the anticipated movement schedule may be included on Form BSEE–0144. This clarification would be necessary if you have, for example, coiled tubing and batch operations and there is not enough time to submit the rig movement 72 hours in advance. Form BSEE–0144 has been revised from its current version to reflect changes based on the proposed rule. Revised Form BSEE–0144 is included in the Appendix to this proposed rule.

Existing paragraph (c) would be replaced with a new paragraph (c) requiring notifications if a MODU or platform rig is to be warm or cold stacked. The notifications for MODUs or platform rigs would include:

—Where the rig is coming from;
—Location where it would be positioned;
—If it would be manned or unmanned; and
—Any changes in the stacking location.

Proposed paragraph (c) would also allow BSEE to have a better understanding of where MODUs and platform rigs are located in case of emergency situations possibly affecting surrounding infrastructure.

New paragraph (d) would require notification to the appropriate District Manager of any construction, repairs, or modifications associated with the drilling package made to the MODU or platform rig, prior to resuming operations after stacking.

New paragraph (e) would also require notification to the District Manager if a drilling rig enters OCS waters regarding where the drilling rig is coming from. The BSEE expects that this notification would provide information about the last location where the drilling rig was conducting operations, or the shipyard location if it is coming from a shipyard, for either a new build or repair. This notification would assist BSEE in verifying the location and movement of the rigs. This notification would also help BSEE verify rig fitness and documentation requirements to allow the rig to conduct operations on the OCS as outlined in proposed § 250.713.

New paragraph (f) would clarify that if the anticipated date for initially moving on or off location changes by more than 24 hours, an updated Rig Movement Notification Report (Form BSEE–0144) would be required. This revision would clarify to operators when a revision or update would be required.

What must I provide if I plan to use a mobile offshore drilling unit (MODU) or lift boat for well operations? (§ 250.713)

The content of this proposed section would be moved from existing § 250.417. This section would make the requirements applicable to all operations covered under this subpart.

Revised paragraph (g) would add current monitoring requirements. Current monitoring is discussed in BSEE NTL 2009–G02, *Ocean Current Monitoring.* These proposed changes would help provide better consistency in permits. Upon publication of the final rule, BSEE would rescind BSEE NTL 2009–G02.

Do I have to develop a dropped objects plan? (§ 250.714)

This section would codify some of the language from BSEE NTL 2009–G36, *Using Alternate Compliance in Safety Systems for Subsea Production Operations,* to help avoid prolonged damage to subsea infrastructure and aid operators' and BSEE's response to a dropped object.

This proposed new section would outline the requirements for developing a dropped objects plan. This proposed section would be applicable to all floating rig units in an area with subsea infrastructure. This section would specify the requirements of a dropped objects plans. The plan would be required to include:

—A description and plot of the path the rig would take while running and pulling the riser;
—A plat showing the location of any subsea wells, production equipment, pipelines, and any other identified debris;
—Modeling of a dropped object's path for various material forms, such as a tubular (*e.g.,* riser or casing) and box (*e.g.,* BOP or tree) with consideration given to metocean conditions;
—A description of communications, procedures, and delegated authorities established with the production host facility to shut-in any active subsea wells, equipment, or pipelines in the event of a dropped object; and
—Any additional information required by the District Manager.

Do I need a global positioning system (GPS) for MODUs and jack-ups? (§ 250.715)

This proposed new section would codify existing BSEE NTL 2013–G01, *Global Positioning System (GPS) for Mobile Offshore Drilling Units (MODUs).* The proposed requirements for GPSs include:

—Providing a robust and reliable means of monitoring the position and tracking the path in real-time if the MODU or jack-up moves from its location during a severe storm;
—Installing and protecting the tracking system's equipment to minimize the risk of the system being disabled;
—Placing the GPS transponders in different locations for redundancy to minimize risk of system failure;
—Capability of transmitting data for at least 7 days after a storm has passed;
—Recording the GPS location data if the MODU or jack-up is moved off location in the event of a storm; and
—Providing BSEE with real-time access to the MODU or jack-up location data.

The BSEE would use the GPS data in emergency situations to minimize potential damage to the offshore infrastructure.

Well Operations

When and how must I secure a well? (§ 250.720)

The content of this proposed section would be moved from existing §§ 250.402, 250.456(j), 250.514(d), 250.614(d), and 250.1709, and would contain the following revisions and additions:

Paragraph (a) would add that the District Manager must be notified when operations are interrupted. This paragraph would also add an example to the list of events that would warrant interruption of operations (currently in § 250.402(a)). Specifically, if there is any observed flow outside the well's casing, operators would have to interrupt operations. The requirement to interrupt operations for the additional event of observing flow outside the well's casing would protect against a failure of the well's structural foundation and a possible environmental incident. The requirement to notify the District Manager would give BSEE awareness of interrupted operations and allow for appropriate regulatory response. This paragraph would also require a negative test in accordance with proposed § 250.721 to ensure wellbore and barrier integrity before removing a subsea BOP stack or surface BOP stack on a mudline suspension well.

Paragraph (a)(2) would also clarify that if there is not enough time to install the required barriers or if special circumstances occur, the District Manager may approve alternate procedures or barriers in accordance with § 250.141. Some options that could be considered include the use of:

—Blind or blind-shear rams;
—Pipe rams and an inside BOP (if hydrocarbons are not exposed in the open hole);
—A drill string hang-off tool; and/or
—Storm packers.

This section would help ensure that during the events previously discussed, the well would be properly secured.

New paragraph (b) would be added to consolidate the content of existing §§ 250.456(j), 250.514(d), 250.614(d), and 250.1709.

What are the requirements for pressure testing casing and liners? (§ 250.721)

The content of this proposed section would be moved from existing §§ 250.423 and 250.425, and would include the following revisions and additions:

Paragraph (a) would increase the minimum test pressure specification for conductor casing, excluding subsea wellheads, from 200 psi in existing regulations (§ 250.423(a)(2)) to 250 psi.

Paragraph (b) would require operators to test each drilling liner and liner-lap before any further operations are continued in the well.

Paragraph (c) would contain requirements for testing each production liner and liner-lap.

Paragraph (d) would clarify that the District Manager may approve or require other casing test pressures.

Proposed new paragraph (e) would add the requirement that operators follow additional pressure test requirements when they plan to produce a well. If a well would be fully cased and cemented, the operator would have to pressure test the well to the maximum anticipated shut-in tubing pressure before perforating the casing or liner. If a well would be an open-hole completion, the operator would have to pressure test the entire well to the maximum anticipated shut-in tubing pressure before drilling the open-hole section of the well.

Proposed paragraph (f) would add a requirement for a PE certification of proposed plans to provide a proper seal if there is an unsatisfactory pressure test.

Proposed paragraph (g) would require a negative pressure test on all wells that use a subsea BOP stack or wells with mudline suspension systems and outline the requirements for those tests.

What are the requirements for prolonged operations in a well? (§ 250.722)

The content of this proposed section would be moved from existing §§ 250.424, 250.518(b), and 250.619(b), with revisions made to clarify the requirements for well integrity for operations continuing longer than 30 days from the previous casing test. If well integrity has deteriorated to a level below minimum safety factors, this section would require repairs or installation of additional casing and subsequent pressure testing, as approved by the District Manager. To obtain approval, a PE certification must be provided showing that he or she reviewed and approved the proposed changes. The results of the pressure test would be submitted to the appropriate District Manager. These changes help ensure a proper wellbore integrity determination to allow operations to continue.

What additional safety measures must I take when I conduct operations on a platform that has producing wells or has other hydrocarbon flow? (§ 250.723)

This proposed section would reflect a combination of existing §§ 250.406, 250.502, and 250.602.

Paragraph (b) would be modified from existing § 250.406(a) to clarify that the emergency shutdown station would be for the production system. This revision would ensure that rig units would be able to shut-in the production system of the host facility.

Paragraphs (d) and (e) would make minor revisions to clarify applicability to all operations covered under proposed Subpart G and to divide the paragraphs to make them easier to read and understand.

What are the real-time monitoring requirements? (§ 250.724)

This proposed new section would include a requirement covering real-time monitoring by onshore personnel of the BOP system, fluid handling system of the rig, and downhole conditions. This section would be added, in part, based on multiple recommendations from various *Deepwater Horizon* investigation reports. Having the real-time data available to onshore personnel would increase the level of oversight throughout operations. Onshore personnel could review data and help rig personnel conduct operations in a safe manner. Also, onshore personnel would be able to assist the rig crew in identifying and evaluating abnormalities or unusual conditions while conducting operations. This section would require that BSEE be provided access to the real-time monitoring facility, upon request. Operators would also be required to record and retain the data at an onshore location for recordkeeping purposes and to make it accessible to BSEE upon request. If real-time monitoring capability is lost during operations, the operator would be required to immediately notify the District Manager, who may require other measures until the real-time monitoring capability is restored.

The BSEE is considering expanding the requirements of this section to other operations, not only those conducted with a subsea BOP or a surface BOP on a floating facility or on any BOP operating in an HPHT environment. The BSEE is specifically soliciting comments on whether the real-time monitoring should be required for all well operations, including shallow water shelf operations. Please provide reasons for your position. If your comment addresses anticipated costs associated with such a requirement, please provide any available supporting data.

Blowout Preventer (BOP) System Requirements

What are the general requirements for BOP systems and system components? (§ 250.730)

This proposed section would reflect a combination of existing §§ 250.416, 250.440, 250.516, 250.616, and 250.1706 and would also include the following revisions and additions:

—Require compliance with API Standard 53, ANSI/API Spec. 6A, ANSI/API Spec. 16A, API Spec. 16C, API Spec. 16D, ANSI/API Spec. 17D, and API Spec. Q1.
—Clarify that the working-pressure rating of each BOP component must exceed the MASP as defined for their operation, such as drilling, completion, or workover. For a subsea BOP, the MASP would be taken at the mudline.
—Add a new performance measure for operators which would require the BOP to be able to meet anticipated wellbore conditions and still be able to perform its expected function of sealing the well.

Proposed paragraph (a) would require compliance with the following API and ANSI/API documents:

API Standard 53—BOP system and components would have to be designed, installed, maintained, inspected, tested, and used according to API Standard 53. The API Standard 53 would be incorporated into the regulations; however, if there is a conflict between API Standard 53 and these regulations, operators would have to follow the requirements of these regulations (*i.e.,* BSEE is requiring that surface BOPs on floating facilities have the same dual shearing requirement as subsea BOPs; API Standard 53 allows for an opt out of this standard with a risk assessment that is not included in the proposed rule). Currently, BSEE regulations only incorporate select sections of API RP 53 (accumulators, maintenance, and inspections). By incorporating new API Standard 53, BSEE would greatly enhance the BOP requirements. As previously discussed in the *Background* section, API Standard 53 is the latest industry consensus standard to update and enhance BOP requirements. After the *Deepwater Horizon* incident, multiple investigations focused on the BOP stack. Every investigation made multiple recommendations to improve the performance and regulation of BOPs. Industry recognized the need to update the previous edition of API RP 53. During the process of updating API RP 53, industry determined that the document needed more substantive content and needed to be raised from an RP to an industry standard. The current API Standard 53 contains the industry consensus standards concerning engineering and operating practices regarding BOP reliability and use. Included in API Standard 53 is a list of normative references (industry standards) that are indispensable to fully utilizing API Standard 53 and to ensure safe and reliable equipment. The normative references include:

—ANSI/API Spec. 6A, *Specification for Wellhead and Christmas Tree Equipment;*
—API Spec. 16A, *Specification for Drill-through Equipment;*
—ANSI/API Spec. 16C, *Specification for Choke and Kill Systems;*
—API Spec. 16D, *Specification for Control Systems for Drilling Well-control Equipment and Control Systems for Diverter Equipment;* and
—ANSI/API Spec. 17D, *Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment*.

Sections of these industry standards apply to BOP systems. The BSEE specifically proposes to incorporate these standards into the regulations as applied to BOP systems to emphasize their significance and make clear the industry standards that must be followed. The BSEE is also requesting comments concerning whether any sections of these documents should not be incorporated by reference.

For general reference, the following table shows relevant topics from each of these industry standards. This table is not a complete list of applicable sections, but is intended to show how these sections interact with API Standard 53.

Industry standard	Applicable topics in API standard 53 (but not limited to):
ANSI/API Spec. 6A, Specification for Wellhead and Christmas Tree Equipment;	Flanges and hubs, Bolting and clamps, Gaskets, Choke and kill lines, Equipment marking and storage, Equipment modifications, Maintenance and testing.
API Spec. 16A, Specification for Drill-through Equipment;	Flanges and hubs, Bolting and clamps, Gaskets, Choke and kill lines, Equipment marking and storage, Maintenance and testing.
ANSI/API Spec. 16C, Specification for Choke and Kill Systems;	Choke manifolds, Choke and kill lines.
API Spec. 16D, Specification for Control Systems for Drilling Well-control Equipment and Control Systems for Diverter Equipment;	Control systems, Maintenance and testing. Electro-hydraulic and multiplex control systems, Auxiliary equipment, Accumulators.

Industry standard	Applicable topics in API standard 53 (but not limited to):
ANSI/API Spec. 17D, Design and Operation of Subsea Production Systems — Subsea Wellhead and Tree Equipment;	Flanges and hubs, Bolting and clamps, Choke and kill lines, Equipment marking and storage, Maintenance and testing.

Paragraph (a)(3) would require that pipe and variable bore rams be capable of closing and sealing on drill pipe, workstrings, or tubing under MASP with the proposed regulator settings of the BOP control system. This new paragraph would help ensure the BOP control regulator set points are sufficient to ensure closure and sealing of the pipe rams.

Paragraph (a)(4) would require a current set of approved schematics to be on the rig and at an onshore location. It would also require that if there are any modifications to the BOP or control system that will change your schematics, operations would be suspended until the operator obtains approval of the new schematics from the District Manager.

Paragraph (b) would require that operators design, fabricate, maintain, and repair the BOP system pursuant to the requirements contained in this subpart, OEM recommendations unless otherwise directed by BSEE, and recognized engineering practices. Personnel performing any repair or maintenance would be required to follow any OEM training or certification recommendations unless otherwise directed by BSEE.

Paragraph (c) would adopt the failure reporting procedures contained in certain API documents. The BSEE would add specific time frames for the completion of these procedures consistent with other previously incorporated API standards and add a requirement that BSEE be notified of any changes to operating or repair procedures adopted to address or in response to a failure. This would allow BSEE to notify the industry and international community of any significant safety issues related to equipment design, and potentially prevent future incidents.

Paragraph (d) would require that if an operator plans to use a BOP stack manufactured after the effective date of the final rule, the operator must use one manufactured pursuant to API Spec. Q1, *Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry.* Currently, BSEE uses API Spec. Q1 in association with the manufacture of safety and pollution prevention equipment. The API Spec. Q1 outlines the requirements for development of a quality management system that provides for continual improvement, emphasizing defect prevention and the reduction of variation. This quality management system facilitates consistent and reliable manufacture. Also added to this section is the option to seek approval to use quality assurance programs other than API Spec. Q1.

The BSEE requests comments concerning whether other industry standards should be incorporated into the regulations that ensure that BOP equipment performs as designed during its service life.

What information must I submit for BOP systems and system components? (§ 250.731)

This proposed section would reflect a combination of existing §§ 250.416, 250.515, 250.615, and 250.1705 with the following revisions and additions:

The introductory text would reflect that the requirements of BOP description submittals would apply to APDs, APMs, and other required submittals. The introductory text would also clarify that the BOP descriptions would not have to be resubmitted with any subsequent permit application or submittal after the initial application that BSEE approved or accepted when the operator moved onto location unless the operator makes changes to what was initially approved or the operator moves off location from that well. This introductory text would also clarify that if the operator is not required to resubmit the BOP information in subsequent applications, then the operator must document why the submittal is not required—in other words, the operator would need to reference the previously approved or accepted application or submittal and state that no changes have been made. The information required under this section would increase the quality of submitted documents and enhance BSEE's review and permitting process.

Paragraph (a) would require submission of the following new BOP descriptions:

—Pressure ratings of BOP equipment;
—Both surface and corresponding subsea pressures for a subsea BOP test;
—Rated capacities of the fluid-gas separator system;
—Control fluid volumes needed to operate each component;
—Control system pressure and regulator settings needed to achieve an effective seal of each ram BOP under MASP;
—Number and volume of accumulator bottles and bottle banks (for subsea BOPs, include both surface and subsea bottles);
—Accumulator pre-charge calculations (for a subsea BOP system, include both the surface and subsea calculations);
—All locking devices; and
—Control fluid volume calculations for the accumulator system (for a subsea BOP system, include both the surface and subsea volumes).

Submission of these descriptions would enhance BSEE's review and understanding of the entire BOP system.

Paragraph (b) would add the following new schematic drawing requirements:

—Labeling the control system alarms and set points;
—Including all locking devices;
—Including control station locations;
—Labeling the type of shear ram(s), size range for variable bore ram(s), size of any fixed ram(s), size of choke and kill lines, and size of subsea BOP gas bleed line(s); and
—Including a cross-section of the riser for a subsea BOP system showing number size, and labeling of all control, supply, choke, and kill lines down to the BOP.

Paragraph (c) would reflect content from existing § 250.416(e) and require submission of the following certifications by a BSEE-approved verification organization verifying that:

—Test data clearly demonstrates the shear ram(s) will shear the drill pipe at the water depth as required in § 250.732;
—The BOP was designed, tested, and maintained to perform at the most extreme anticipated conditions; and
—The accumulator system has sufficient fluid to function the BOP system without assistance from the charging system.

Paragraph (d) would require additional certification if an operator uses a subsea BOP, a BOP in an HPHT environment, or a surface BOP on a floating facility. The certification would include verification of the following:

—The BOP stack is designed for the specific equipment on the rig and for the specific well design;

—The BOP stack has not been compromised or damaged from previous service; and
—The BOP stack will operate in the conditions in which it will be used.

The BSEE is considering expanding the requirements of this paragraph to all BOPs. The BSEE is specifically soliciting comments on whether this certification requirement should be applied to all well operations, including shallow water shelf operations and operations with surface BOPs. Please provide reasons for your position. If your comment addresses anticipated costs associated with such a requirement, please provide any available supporting data.

Paragraph (e) would be entirely new for subsea BOPs. This paragraph would require a listing of the functions with sequences and timing of autoshear, deadman, and emergency disconnect sequence (EDS) systems. These emergency systems were the topic of many *Deepwater Horizon* investigations and multiple associated recommendations. It is BSEE's position that submission of this additional information would improve BSEE's ability to oversee the use of these critical systems.

Paragraph (f) would add a certification requirement stating that the Mechanical Integrity Assessment Report required in proposed § 250.732(d) has been submitted within the past 12 months for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility.

The items covered under this section have not been routinely submitted to BSEE or obtained by the operators charged with responsibility to maintain well control, and BSEE believes these items are important to fully understand the entire BOP system and to verify that it would perform in an acceptable manner.

What are the BSEE-approved verification organization requirements for BOP systems and system components? (§ 250.732)

This proposed section would reflect a combination of existing §§ 250.416, 250.515, 250.615, and 250.1705, along with new requirements. This proposed section is necessary to ensure that BSEE receives accurate information regarding BOP systems so that BSEE may ensure the system is appropriate for the proposed use. The third-party verification and documentation by a BSEE-approved verification organization would enhance the BSEE review during the permitting process. The objective is to have this equipment monitored during its entire lifecycle by an independent third-party to verify compliance with BSEE requirements, OEM recommendations, and recognized engineering practices. The BSEE believes that the importance and complexity of BOP systems and the fact that they might be operated at various worldwide locations throughout their service life warrants a thorough and regular assessment of the systems and verification that design, installation, maintenance, inspection, and repair activities are documented and traceable.

The list of approved verification organizations would be limited to those that can clearly demonstrate the capability to perform this comprehensive detailed technical analysis.

Paragraph (a) would clarify that BSEE will maintain a list of BSEE-approved verification organizations, and also outline criteria to become a BSEE-approved verification organization.

Paragraph (b) would be 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.

Paragraph (c) would require a special verification process for BOP and related equipment being used in HPHT environments because the design conditions required for an HPHT environment exceed the limits of existing engineering standards. The use of a BSEE-approved verification body would provide BSEE with an additional layer of review and verification at all steps in the development process. The paragraph makes it clear that the operator has the burden of clearly demonstrating the reliability of the equipment through a comprehensive review of the design, testing, and fabrication process.

Paragraph (d) would require an annual submittal of a Mechanical Integrity Assessment Report for a subsea BOP, a BOP used in HPHT environment, or a surface BOP on a floating facility. This paragraph would outline the requirements of a Mechanical Integrity Assessment report.

Paragraph (e) would require operators to make all documentation that supports the requirements of this section available to BSEE upon request.

The BSEE believes that using a third-party to verify the testing and qualification of BOP equipment would ensure consistent results and provide a reasonable assurance of the performance of this equipment. Based on previous studies available on the Web site of BSEE's Technology Assessment Program (available at: *http://www.bsee.gov/Technology-and-Research/Technology-Assessment-Programs/Index*), BSEE believes that the development of more rigorous industry testing protocols is critical to demonstrating the performance of BOP equipment.

The BSEE requests comments on the following issues associated with this section:

—On the issue of standardized test protocols and whether there are any specific procedures that should be considered for adoption.
—On the importance of applying forces in tension or compression during the actual shearing tests.
—On what criteria should be used to qualify a BSEE-approved verification organization and whether OEMs should be considered for the program.
—On the issue of updating test protocols and criteria used by verification organizations, given the likelihood of future improvements to BOP technology.

What are the requirements for a surface BOP stack? (§ 250.733)

This proposed section would be a combination of existing §§ 250.441, 250.443, 250.516, 250.616, and 250.1706 with the following revisions and additions:

Paragraph (a) would contain revisions clarifying its applicability to all operations covered under Subpart G.

Paragraph (a) would also clarify that the blind-shear rams would have to be able to shear the drill pipe, workstring, tubing, and any electric-, wire-, or slick-line. If the blind-shear ram could not cut and seal electric-, wire-, or slick-line under MASP, an alternative cutting device would be required on the rig floor during operations that require their use, to cut the wire before closing the BOP. This requirement would be necessary to ensure that there are means to cut the wire in the hole, even if it is an external cutting device.

Paragraph (b) would codify BSEE policy and would:

—Clarify that when using a surface BOP on a floating production facility:
—the same BOP requirements apply as in § 250.734(a)(1), and
—a dual bore riser configuration would be required for risers installed after the effective date of this rule before drilling or operating in any hole section or interval where hydrocarbons may be exposed to the well;
—Require risers to meet the design requirements of API RP 2RD;

—Clarify that the annulus between the risers must be monitored during operations;
—Require a description of the monitoring plan in the APD or APM, including how you would secure the well if a leak is detected; and
—Clarify that the inner riser for a dual riser configuration is subject to the requirements for testing the casing or liner.

API Standard 53 does not impose dual shear requirements for surface BOPs on floating facilities; however, this proposed rule would require dual shears. If there is any conflict between the documents incorporated by reference and these regulations, the operator would be required to follow these regulations.

Proposed paragraph (c) would contain content from current § 250.443(c) for surface BOP stacks to contain one side outlet for a choke line and one side outlet for a kill line. There would be a new requirement that the outlet valves must hold pressure from both directions.

Existing § 250.441(d) would not be carried forward to proposed § 250.733 because it is unnecessary to state that the regulations covered under this subpart are required.

Proposed paragraph (d) would contain content from a portion of existing § 250.443(d). An addition, this paragraph would require that the outlet valves must be full-bore, full-opening. This would prevent leaks into and out of the BOP stacks.

Proposed paragraph (e) would require installation of hydraulically operated locks.

Proposed Paragraph (f) would add specific requirements for a surface BOP used in HPHT environments, if operations are suspended to make repairs to any part of the BOP system. The BSEE is considering requiring the same dual shear ram requirements in proposed § 250.734(a)(1) for BOPs used in HPHT environments. The BSEE is requesting comments on requiring dual shear rams for BOPs used in HPHT environments, and how long it would take to comply with the dual shear requirement for BOPs used in HPHT environments. If your comment addresses anticipated costs associated with such a requirement, please provide any available supporting data.

What are the requirements for a subsea BOP system? (§ 250.734)

This proposed section would reflect a combination of existing §§ 250.442, 250.443, 250.516, 250.616, and 250.1706.

Proposed paragraph (a)(1) would require two BOPs equipped with shear rams. This new requirement would correspond to API Standard 53, and would increase the shearing capabilities of a BOP stack. This paragraph would also clarify that both shear rams would have to be able to shear at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies, which include heavy-weight pipe or collars), workstring, and tubing, as well as be able to shear the liner casing landing string, shear sub on subsea test tree, and any electric-, wire-, or slick-line in the hole under MASP. At least one shear ram would have to be capable of sealing the wellbore under MASP after shearing. Any non-sealing shear rams would have to be installed below the sealing shear rams. These requirements would help ensure that shearing the pipe and sealing the wellbore could be achieved.

Proposed paragraph (a)(3) would clarify that the accumulator capacity would have to be located subsea to provide closure of the BOP components and operate critical functions in case of a loss of the power fluid connection to the surface. The critical functions and components would be defined as each shear ram, choke and kill side outlet valves, one pipe ram, and lower marine riser package (LMRP) disconnect. This paragraph would also require that the subsea accumulator system have the capability of delivering fluid to each ROV function *i.e.,* flying leads. The accumulator would be required to have dedicated independent bottles for the autoshear, deadman, and EDS systems. The subsea accumulator would have to be capable of performing under MASP. These new requirements would ensure that the subsea accumulators would be able to provide fluid to each ROV function. The reference to API RP 53 in current § 250.442(c) would not be carried forward to the proposed paragraph.

Proposed paragraph (a)(4) would include requirements that the ROV would have to be able to perform critical BOP functions, including opening and closing each shear ram, choke and kill side outlet valves, all pipe rams, and the LMRP disconnect under MASP conditions. This paragraph would also include a new requirement that the ROV panels must be compliant with API RP 17H.

Proposed paragraph (a)(5) would require communication between the ROV crew and the rig personnel familiar with the BOP. This communication would help ROV crews perform proper operations and better determine appropriate BOP conditions.

Proposed paragraph (a)(6) would include requirements of an autoshear, deadman, and EDS system for dynamically positioned rigs, and autoshear and deadman systems for moored rigs. This paragraph would also require each emergency function to include both shear rams closing under MASP. The sequencing of each emergency function would have to provide for the lower shear ram beginning closure before the upper shear ram would begin closure. Also, the control system for the emergency functions would be required to be a fail-safe design, and each step in the logic would have to be independent of the previous step being completed. These revisions to the emergency functions would help provide the best means to carry out the intended functions. In the past, some BOP systems have only included one shear ram in the emergency functions, and these additions would ensure including both shear rams in those functions.

Proposed paragraph (a)(7) would add acoustic system requirements similar to current § 250.442(f)(3). The revision puts the acoustic system option into its own designated paragraph. It would expand what must be provided to the BSEE District Manager if an acoustic system is to be used for a subsea BOP.

Proposed paragraph (a)(12) would be revised to connect this paragraph to § 250.720(b). This revision would clarify the intent of this existing regulation and ensure that procedures are submitted for review and approval in permits.

Proposed paragraph (a)(14) would revise a current requirements from §§ 250.443(c) and (d), 250.516, 250.616, and 250.1706. The proposed rule would require subsea BOPs to contain two side outlets for the choke line and two side outlets for the kill line. Each side outlet would be required to have two full-bore, full-opening valves. The proposed section would require these valves to be pressure-holding from both directions. This section would also require a side outlet below each sealing shear ram. Operators may have a pipe ram or rams between the shearing ram and side outlet. This would enhance well-control capability for subsea BOPs.

Proposed paragraph (a)(15) would require operators to install a gas bleed line with two valves for the annular preventer. If dual annulars would be installed with one on the LMRP and one on the lower BOP stack, each annular would have to have a gas bleed line. The two valves would need to be able to hold pressure from both directions.

Proposed paragraph (a)(16) would require subsea BOP systems to have mechanisms capable of:

—Positioning the entire pipe, including connection, completely within the area of the shearing blade necessary to ensure shearing would occur any time the shear rams are activated. This mechanism could not be another ram BOP or annular preventer;

—Mitigating compression of the pipe stub between the shearing rams. (This provision was added based upon multiple *Deepwater Horizon* investigation recommendations; the blind shear ram (BSR) could not fully close and seal because the drill pipe was forced to the side of the wellbore and outside of the BSR cutting surface); and

—Monitoring the subsea electronic module batteries in the BOP control pods.

New paragraph (b) would codify BSEE policy and require that if operations are suspended to make repairs to the BOP, operations would have to be stopped at a safe downhole location. This section would also require that before resuming operations, the operator would need to do the following:

—Submit a revised permit with a report from a BSEE-approved verification organization documenting the repairs and that the BOP is fit for service;

—Perform a new BOP test upon relatch; and

—Receive approval from the District Manager.

Paragraph (b) would help BSEE ensure the BOPs have proper verification after repairs and that BSEE would be aware of the repairs.

New paragraph (c) would codify BSEE policy. Additions to this section would provide 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 by this subpart for the open water drilling operation. However, before drilling out the surface casing, the operator would be required to submit for approval a revised APD, including the third-party verifications required in this subpart. This paragraph would allow operators to perform certain operations prior to verification to facilitate the timing and scheduling of work.

The BSEE is also soliciting specific comments on the following possible additional requirements:

—Under proposed paragraph (a)(1)(ii) of this section, requiring that both shear rams be able to shear the appropriate area for the casing landing string. Also please comment on whether there would be utility in installing the non-sealing shear ram above the sealing shear ram, and how it would affect the sequence of ram closure;

—Under proposed paragraph (a)(16) of this section, requiring a position indicator for each ram BOP, wellhead connector, and LMRP connector. The position indicator would have to be viewable by the ROV during operations and in the event of a disconnect of the LMRP; and

—Under proposed paragraph (a)(16) of this section, requiring sensing and displaying pressure within the BOP. This mechanism would have to be viewable by the ROV during operations and in the event of a disconnect of the LMRP.

These proposed requirements are in part based on various *Deepwater Horizon* investigation recommendations.[3] These proposed requirements would help identify the status of various BOP components under emergency situations to assist in emergency well control. If your comment addresses anticipated costs associated with any of the above requirements, please provide any available supporting data.

The BSEE is also soliciting comments on whether there are other options besides the use of shear rams to provide redundant shearing capability while ensuring the same level of safety and environmental protection.

What associated systems and related equipment must all BOP systems include? (§ 250.735)

This proposed section would reflect a combination of existing §§ 250.441, 250.443, 250.516, 250.616, and 250.1706.

Proposed paragraph (a) would contain content from existing § 250.441(c), with the following changes:

—Clarification that the requirements are for a surface accumulator system;

—Clarification that the system would have to operate all BOP functions, including shearing pipe and sealing the well against MASP without assistance from a charging system; and

—Clarification that these provisions would apply to all BOP systems, not just surface BOP stacks.

This revision would clarify existing regulations and ensure the BOP system is capable of operating all critical functions.

Proposed paragraph (b) would add that the independent power source must possess sufficient capability to close and hold closed all BOP components under MASP.

Proposed paragraph (e) would add that the kill line must be installed beneath at least one pipe ram.

What are the requirements for choke manifolds, kelly valves, inside BOPs, and drill string safety valves? (§ 250.736)

This proposed section would reflect a combination of existing §§ 250.444, 250.445, 250.516, 250.616, 250.1707, with minor edits to clarify applicability to all operations covered under this subpart.

What are the BOP system testing requirements? (§ 250.737)

This proposed section would reflect a combination of existing §§ 250.447, 250.448, 250.449, 250.517, 250.617, 250.1707, and be revised as follows:

Proposed paragraph (a) would reorganize pressure testing frequency requirements into one section. A new provision would be added that the District Manager may require more frequent testing for the BOP system if conditions or BOP performance warrant. Additionally, by consolidating the pressure test requirements for drilling, workovers, completions, and decommissioning into one section, BSEE would revise the workover and decommissioning BOP testing frequency to be consistent with the 14-day frequency for drilling and completions. Some operations use the same rigs and BOP systems; therefore, to ensure consistency among different operations involving the same equipment, BSEE proposes harmonizing the requirements for that type of equipment. Also, BOP equipment that meets the new requirements of this proposed rule would perform in a more reliable manner and provide additional assurances that wells can be safely shut-in when necessary. The BSEE requests comments on whether this increase in equipment reliability justifies expanding the workover and decommissioning BOP testing frequency.

Proposed paragraph (b) would add a table to organize pressure testing requirements. Paragraph (b)(1) would be for a low-pressure test, and the required test pressure range would increase 50 psi to be between 250 to 350 psi. Paragraph (b)(2) would add high-pressure test requirements for BSR-type

[3] For example, BOP position indicator and display of pressures—National Oil Spill Commission recommendation D4; Centering pipe for shearing—DOI JIT recommendation D6; ROV functions and capabilities—Offshore Energy Safety Advisory Committee recommendation 07; Monitoring Subsea electronic module batteries—DOI JIT recommendation D2.

BOPs, outside of all choke and kill side-outlet valves (and annular gas-bleed valves for subsea BOP), and inside of all choke and kill side-outlet valves below the uppermost ram. Paragraph (b)(3) would add high-pressure test requirements for inside of choke or kill valves (and annular gas bleed valves for subsea BOP) above the uppermost ram BOP and would clarify test pressure procedures.

Proposed paragraph (c) would require that each test must hold pressure for 5 minutes, which must be recorded on a 4-hour chart. This would allow the chart to display enough line curvature length to detect a leak during the test.

Proposed paragraph (d) would be reorganized into a table and additional testing requirements would be added. Revisions to the existing testing requirements would be:

Proposed paragraph (d)(1) would add a reference to the testing requirements in API Standard 53. Operators would be required to follow all testing requirements covered in API Standard 53, unless testing requirements conflict with BSEE regulations, in which case operators would be required to follow BSEE regulations.

Proposed paragraph (d)(2) would add requirements to use water to test a surface BOP system. This paragraph would also require that operators submit test procedures in their APD or APM for District Manager approval and contact the District Manager at least 72 hours prior to beginning the test to allow a BSEE representative to witness testing.

Proposed paragraph (d)(3) would require that operators submit stump test procedures for a subsea BOP system in their APD or APM for District Manager approval and require that stump tests follow the pressure test procedures set forth in paragraphs (b) and (c).

Proposed paragraph (d)(4) would outline the requirements for performing the initial subsea BOP test on the seafloor.

Proposed paragraph (d)(5) would expand testing requirements for two BOP control stations. The operator would be required to designate the control stations as primary and secondary and function-test each station weekly. The control station used to perform the pressure test would be required to be alternated between each pressure test. For a subsea BOP, the operator would be required to rotate the pods between each control station during the weekly function tests and alternate the pod used for pressure testing between each pressure test. If additional control stations are installed, they would have to be tested every 14 days.

Proposed paragraph (d)(7) would be a new requirement to pressure test annular type BOPs against the smallest pipe in use.

Proposed paragraph (d)(10) would be a new requirement to function test BSR BOPs every 14 days. This requirement would align the timing of the function and pressure tests.

Proposed paragraph (d)(12) would expand criteria for ROV testing to include testing and verifying closure capability of all intervention functions of the subsea BOP. These new provisions include requirements that:

—Each ROV must be fully compatible with the BOP stack ROV intervention panels;
—Operators must submit test procedures, including how they will test each ROV intervention function; and
—Operators must document all test results and make them available to BSEE upon request.

Proposed paragraph (d)(13) would expand requirements for function testing autoshear, deadman, and EDS systems on subsea BOPs. The test procedures must be submitted for District Manager approval, and the proposed rule would require that the procedures include:

—Schematics of the circuitry of the system that would be used during an autoshear or deadman event;
—The approved schematics of the BOP control system with the actions and sequence of events that would take place; and
—How the ROV would be used during the well-control operations.

Prior to conducting the test, the well is to be in a secure configuration with appropriate barriers. The testing of the deadman system on the seafloor would have to indicate the discharge pressure of the subsea accumulator system throughout the test. During the initial test of the deadman system, the operator would need to have the ability to quickly disconnect the LMRP. The operators would also have to submit the quick-disconnect procedures with the deadman test procedures in the APD or APM. The BSR(s) would need to be pressure tested according to paragraphs (b) and (c) of this section. The operator would have to include in its procedure a description of how it plans to verify closure of a casing shear ram if installed. All test results would have to be documented and submitted to BSEE upon request.

Proposed paragraph (e) would require that operators notify BSEE at least 72 hours in advance of any shear ram tests in which the operators will shear pipe. This would allow better scheduling for BSEE personnel to witness these tests.

What must I do in certain situations involving BOP equipment or systems? (§ 250.738)

This proposed section would be a combination of existing §§ 250.451 and 250.517. Additional requirements would be added as follows:

As recommended by the DOI JIT investigation recommendation E2, proposed paragraph (a) would require the operator to notify the District Manager of any problems or irregularities, including leaks, if BOP equipment does not hold the required pressure during testing.

Proposed paragraph (b) would require the operator to receive approval from the District Manager prior to resuming operations after replacing, repairing, or reconfiguring the BOP system. To obtain approval, the operator would have to submit a report from a BSEE-approved verification organization attesting that the BOP system is fit for service. Any repair or replacement parts would have to be manufactured under a quality assurance program and would have to meet or exceed the performance of the original part produced by the OEM.

Proposed paragraph (d) would require the operator to notify the District Manager of any problems or irregularities, including leaks, if a BOP control station or pod does not function properly and suspend operations until the station or pod operates properly.

Proposed paragraph (e) would be revised to clarify that two sets of pipe rams must be capable of sealing around the smaller size pipe to be consistent with §§ 250.733(a) and 250.734(a)(1), which require the capability to close and seal on the tubular body of any drill pipe, workstring, and tubing.

Proposed paragraph (f) would add new requirements if the operator proposes to install casing rams or casing shear rams in a surface BOP stack. The ram bonnets would have to test to the rated working pressure or MASP plus 500 psi and be tested before running casing. The BOP would still need to be capable of sealing the well after the casing is sheared. If the installation would be a change from the approved APM or APD, the operator must notify and receive approval from the District Manager.

Proposed paragraph (i) would require that, after pipe or casing is sheared either intentionally or unintentionally, the operator would have to retrieve, inspect, and test the BOP as well as submit a report to the District Manager from a BSEE-approved verification body, stating that the BOP is fit to return to service.

Proposed paragraph (j) would add a requirement that an operator must have a minimum of two barriers in place prior to removal of the BOP stack. The District Manager would have to approve the two barriers and may require additional barriers prior to removal. This requirement is consistent with similar requirements in current § 250.420(b)(3), and is necessary to ensure that the well is placed in a safe condition prior to BOP removal.

Proposed paragraph (k) would add new requirements for re-establishing power to a BOP stack after a deadman or autoshear activation. Prior to re-establishing power, the operator would have to examine the system to determine if the possibility exists for the BSR opening immediately upon re-establishing power to the BOP stack. If this is a possibility, the opening function would have to be placed in the block position before power is re-established to the stack. The operator would have to contact the District Manager to receive approval of procedures for re-establishing power and functions prior to latching up the BOP stack or re-establishing power to the stack.

Proposed paragraph (l) would establish requirements for test rams. The initial BOP test after latch-up would have to be done with a test tool, and the wellhead/BOP connection would have to be tested to the maximum ram-test pressure approved for the well in the APD or APM. All hydraulically operated BOP components would have to function as designed during the well connection test.

Proposed paragraph (m) would add requirements for additional well-control equipment that operators may use, but which are not required in this subpart. The operator would have to request approval from the appropriate District Manager, submit a report from a BSEE-approved verification organization on the design and suitability of the equipment for its intended use, and submit any other information required by the District Manager. The District Manager may impose requirements concerning the equipment's capabilities, operation, and testing.

Proposed paragraph (n) would clarify that pipe and variable bore rams that have no current utility and would not be used for well-control purposes would not have to be pressure and function tested, until they are intended to be used during operations. Operators would have to indicate which pipe and variable bore rams meet this criteria in their APD or APM and label those rams on all BOP control panels.

Proposed paragraph (o) would include new requirements applicable to redundant well-control components in BOP systems that are in addition to components required in Subpart G. If any redundant component fails a test, you must submit a report from a BSEE-approved verification organization that describes the failure and confirms that there is no impact on the BOP that will make it unfit for well-control purposes. This report would have to be submitted to the District Manager, and operators may not resume operations until they receive the District Manager's approval. The District Manager may require operators to submit additional information before approving continued operations.

Proposed paragraph (p) would add new requirements that operators would have to meet if they need to position the bottom hole assembly across the BOP for tripping or any other operations, including:

—Ensuring that the well is stable at least 30 minutes before positioning the bottom hole assembly across the BOP, and

—Including in the well-control plan (required by proposed § 250.710(b)) procedures for immediately removing the bottom hole assembly from across the BOP in the event of a well control or emergency situation before exceeding MASP conditions. This would ensure that the operational conditions would not exceed the BOP design specifications.

What are the BOP maintenance and inspection requirements? (§ 250.739)

This proposed section would reflect a combination of existing §§ 250.446, 250.517, 250.618, and 250.1708 with the following revisions:

Proposed paragraph (a) would add that the BOP maintenance and inspections must meet or exceed OEM recommendations, recognized engineering practices, and industry standards incorporated by reference into the regulations, including all provisions in API Standard 53. In the past, BSEE has only required compliance with select sections of API RP 53. By incorporating the updated edition (API Standard 53), BSEE would increase the overall maintenance and inspection requirements.

Proposed paragraph (b) would be a new requirement that details the procedures for a complete breakdown and inspection of the BOP and every associated component every 5 years. This paragraph would also clarify that the complete breakdown and inspection may not be performed in phased intervals. Also, during this complete breakdown and inspection, a BSEE-approved verification organization would have to be present documenting the inspection and any problems encountered and produce a detailed report. This independent third-party report would have to be available to BSEE upon request. The BSEE is aware that, in the past, various components of BOP stacks have not had this type of inspection for more than 10 years. However, BSEE feels it is essential to ensure that every component on the BOP stack has a complete breakdown and detailed inspection every 5 years.

Proposed paragraph (c) would revise the subsea BOP inspection requirement to include visual inspection of the wellhead and remove the word ''television.''

Proposed paragraph (d) would require that the personnel who maintain, inspect, or repair BOPs or other critical components meet the qualifications and training criteria specified by the OEM and that such maintenance, inspection, and repair be undertaken in accordance with recognized engineering practices. This provision is necessary to ensure that any personnel working on BOPs are properly qualified to perform any maintenance, inspections, or repairs.

Proposed paragraph (e) would require that all records be made available to BSEE upon request. This provision would also require operators to ensure, by contract or otherwise, that a rig owner maintains BOP records on the rig for 2 years from the date the records are created or longer if directed by BSEE. Also, all design, maintenance, inspection, and repair records must be maintained at an onshore location for the service life of the equipment.

Records and Reporting

What records must I keep? (§ 250.740)

This proposed section would include content from existing § 250.466 and would make the requirements applicable to all operations covered under this subpart. This section would also include recordkeeping of all tests conducted and real-time monitoring data gathered during operations.

How long must I keep records? (§ 250.741)

This proposed section would contain content from existing § 250.467 with minor edits to clarify applicability to all operations covered under this subpart. This section would also include how long records for real-time monitoring data must be kept.

What well records am I required to submit? (§ 250.742)

This proposed section would contain some content from existing § 250.468. The remainder of the existing § 250.468 would be included in proposed § 250.743.

What are the well activity reporting requirements? (§ 250.743)

This proposed section would include content from existing paragraphs (b) and (c) of existing § 250.468, BSEE NTL 2009–G20, *Standard Reporting Period for the Well Activity Report,* and BSEE NTL 2009–G21, *Standard Conditions of Approval for Well Activities* with the following changes:

Proposed paragraph (a) would clarify the well activity reporting timeframe for the GOM OCS Region as currently set forth in NTL 2009–G20. This new revision would help clarify when to submit the WARs (Form BSEE–0133) and accompanying Form BSEE–0133S, Open Hole Data Report. The District Manager may require more frequent submittal of the WAR on a case-by-case basis.

Proposed paragraph (c) would be revised to include in the WAR, information from NTL 2009–G21 describing the operations conducted, any abnormal or significant events that affect the permitted operation, verbal approvals, the wells as-built drawings, casing fluid weights, shoe tests, test pressures at surface conditions, and status of the well at the end of the reporting period. The final WAR would include the date operations finished. This paragraph would also require describing the returns for casing cementing operations. This data would provide BSEE with accurate information regarding the operations and well conditions and verify the operator's compliance with past approvals.

Upon final publication of this rule, BSEE will rescind any NTLs that are superseded by this section in the final rule.

What are the end of operation reporting requirements? (§ 250.744)

This proposed section would combine provisions from existing §§ 250.465, 250.1712, 250.1717, and NTL 2009–G21, *Standard Conditions of Approval for Well Activities,* and include clarifications concerning the contents of the EOR (Form BSEE–0125). This information would provide BSEE with important well data and provide a better understanding of the operations and well conditions.

What other well records could I be required to submit? (§ 250.745)

This proposed section would reflect content from existing § 250.469.

What are the recordkeeping requirements for casing, liner, and BOP tests, and inspections of BOP systems and marine risers? (§ 250.746)

This proposed section would reflect a combination of existing §§ 250.426, 250.450, 250.517, 250.617, and 250.1707, with the following revisions:

Proposed paragraph (b) would add the requirement for the designated rig or contractor representative (*e.g.,* the offshore installation manager) and pump operator to sign and date the pressure charts and reports as correct in addition to the onsite lessee representative (*e.g.,* the company man).

Proposed paragraph (d) would be clarify that identification of the pods would not apply to coiled tubing and snubbing units.

Proposed paragraph (e) would clarify that any leaks observed during testing or observed from the control station are considered irregularities and would have to be reported to BSEE. Operations would have to be suspended until BSEE grants approval to continue. This revision would allow BSEE to be notified of the BOP irregularities to help determine BOP operability.

Proposed paragraph (f) would add the timeframe for keeping the records for a minimum of 2 years after completion of the operation and require that the records would have to be made available to BSEE upon request. The BSEE would be able to use this data as a tool to verify the operator's compliance with past approvals and regulations.

Subpart P—Sulphur Operations

Well-control drills (§ 250.1612)

This section would update the reference for the drilling crew requirements under proposed § 250.711.

Subpart Q—Decommissioning Activities

What are the general requirements for decommissioning? (§ 250.1703)

This section would be revised as follows:

Paragraph (b) would include a new requirement that all packers and bridge plugs would have to comply with API Spec. 11D1, which would help ensure that packers and bridge plugs conform to design, manufacture, and testing criteria to increase reliability and to ensure appropriate use of the equipment. Currently, BSEE does not have specific guidelines for packers and bridge plugs, and this addition would help BSEE verify that wells have been properly plugged in accordance with API Spec. 11D1.

Paragraph (f) would be revised to add reference to the requirements of new Subpart G. This would make Subpart G applicable to decommissioning.

When must I submit decommissioning applications and reports? (§ 250.1704)

Paragraph (g) would be revised by removing current paragraphs (g)(2), (g)(4), and (g)(6) and the associated instructions in the third column, as well as by revising the numbering of current paragraphs (g)(3) and (g)(5) to (g)(2) and (g)(3), respectively, and by updating the applicable citations. Proposed paragraph (h) would be added to state the requirements for when to submit the EOR, making it clear when operators would have to submit the EOR versus an APM.

What BOP information must I submit? (§ 250.1705)

This section would be removed and reserved. The content of this section would be moved to proposed §§ 250.731 and 250.732.

Coiled tubing and snubbing operations. (§ 250.1706)

Paragraphs (a) through (e) would be moved to proposed §§ 250.730, 250.733, 250.734, and 250.735. The section heading would be renamed from, *What are the requirements for blowout prevention equipment?* to *Coiled tubing and snubbing operations.* Remaining paragraphs (f) through (h) would be redesignated as (a) through (c).

What are the requirements for blowout preventer system testing, records, and drills? (§ 250.1707)

This section would be removed and reserved. The content of this section would be moved to proposed §§ 250.711, 250.736, 250.737, and 250.746.

What are my BOP inspection and maintenance requirements? (§ 250.1708)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.739.

What are my well-control fluid requirements? (§ 250.1709)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.720.

How must I permanently plug a well? (§ 250.1715)

Paragraph (a)(3)(iii)(B) of this section would be revised to add that a ''casing'' bridge plug would be set 50 to 100 feet above the top of the perforated interval. Adding the word ''casing,'' clarifies the plug requirements for the applicable scenario. The BSEE has been contacted by multiple companies requesting clarification of this type of requirement. The BSEE believes that the proposed addition of ''casing'' adequately addresses the concerns stated by industry participants and explains the correct intention of this proposed section.

After I permanently plug a well, what information must I submit? (§ 250.1717)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.744.

If I temporarily abandon a well that I plan to re-enter, what must I do? (§ 250.1721)

This section would remove existing paragraph (g) and redesignate paragraph (h) as (g). The content of existing paragraph (g) would be required by proposed § 250.744.

Additional Comments Solicited

In addition to the input previously requested, BSEE requests public comment on the following issues.

(1) Rig Daily Operating Rates

Throughout the proposed rule and corresponding economic analysis, the BSEE has estimated the daily rig rates and made assumptions based on that estimation. The BSEE is soliciting comments on the appropriateness of the values presented and is further requesting corresponding data to substantiate any comments. The BSEE can use this data to update the values in the final rule. The following chart shows the daily operating costs used within the economic analysis.

Rig type	Estimated daily operating cost
Rigs that utilize a subsea BOP (e.g. drillships, semi-submersibles)	*$1,000,000*
Rigs that utilize a surface BOP (e.g. jack-ups, lift boats)	*200,000*

(2) Failure of Equipment Reporting and Information Dissemination

Several of the standards that are being incorporated by reference include a process for the reporting of failures of equipment back to the OEM. The BSEE proposes to adopt these processes and add a requirement that BSEE be notified of major issues that require a design change. This notification would help to ensure that the domestic and international communities are able to react quickly to address potential safety issues.

Because identical equipment designs are often used by multiple operators, ensuring the timely reporting of failures involving critical equipment can assist in identifying trends and play an important role preventing future incidents. The BSEE believes that a more formalized method of collecting, analyzing, and disseminating failure data is warranted, especially for equipment failures that do not result in a reportable incident. The need for this type of program was clearly demonstrated following the December 2012 failures of certain bolts in the GOM. Subsequent investigations revealed that although these failures had been occurring over a period of years, most of the industry was not aware of the safety issues. Even after safety alerts were issued by BSEE and the OEM, some operators claimed that the amount and quality of data that was released was not sufficient. The BSEE has received comments from the industry stating that legal and commercial barriers discouraged the voluntary reporting of this type of data.

The BSEE requests comments on whether this information should be provided to the agency or a third-party to ensure the timely analysis and wide-spread communication of the data. For example, are there programs in other industries that could serve as a model for reporting failure of OCS equipment? Are there third-party organizations that would be good candidates for collecting and analyzing information and issuing safety alerts? What type of data should be collected and disseminated? How should information on international operations be collected and disseminated?

(3) Maintenance and Training

Preventative and remedial maintenance is critical to maintaining a satisfactory level of reliability during the operational life of critical equipment. A lifecycle management approach toward safety critical equipment is especially important as the industry moves into the development of deepwater and HPHT reservoirs. More rigorous inspection, maintenance, and repair practices and methods may be needed to ensure the reliable performance of this equipment in these environments.

The BSEE requests comments on whether there are any additional standards or practices related to the repair and maintenance of this equipment that should be considered by BSEE. The BSEE has completed a major study related to maintenance, inspection and test activities, and management systems. The BSEE requests information on any work that is being conducted by the industry to develop industry standards concerning these activities. The BSEE also requests comments on whether there are predictive maintenance techniques or risk-based maintenance approaches that should be used to supplement the proposed requirements.

The proposed regulation requires the use of real-time monitoring systems for operations with a subsea BOP stack or involving HPHT environments. The BSEE requests comments on the use of continuous remote monitoring and diagnostic analysis of critical equipment using condition-based maintenance (CBM). With CBM, critical equipment can be monitored and maintenance actions performed based on information collected through constant real-time monitoring of critical equipment. These systems may provide early warning of potential problems that could be addressed before costly and dangerous catastrophic failures. The BSEE believes that these systems may help to verify the integrity of the overall system during drilling operations in a more timely and efficient manner.

The BSEE believes that it is important that components and replacement parts for critical equipment meet quality design and engineering standards that ensure that this equipment operates safely and as originally designed during its service life. Additionally, the equipment must be repaired and maintained by highly trained personnel that understand the OEM design and repair standards. These requirements are implicit in the Safety and Environmental Management Systems (SEMS) requirements contained in existing BSEE regulations. The BSEE requests comments on what type of training and certification programs should be required for personnel working on this critical equipment. Are there training and certification programs being used in other industries that can serve as a model for the OCS personnel? How should repairs being performed outside U.S. waters be monitored? Are there any existing oil and gas training and certification programs that should be incorporated into the regulations?

(4) Verification of BOP Performance

The BSEE believes that the proposed requirements would provide the agency with additional assurance related to the overall reliability of equipment in the future. The industry and BSEE currently rely on function and hydrostatic tests to verify the performance of BOP equipment in the field. These tests have traditionally been the primary method of verifying the capability of in-service equipment.

In recent years, the industry has raised concerns related to benefits of pressure and functional testing of subsea BOPs versus the costs and potential operational issues. The BSEE requests comments on the adequacy of the current functional and pressure test requirements in predicting the performance of this equipment in subsequent drilling operations. Under what circumstances or environments should the testing frequency be increased or decreased? Are there additional technologies, processes, or procedures that can be used to supplement existing requirements and provide additional assurances related to the performance of this equipment?

The latest industry study on BOP reliability and testing frequency was submitted to the MMS in 2009. What type of additional research and data collection is needed or has already been conducted to verify the reliability of this equipment? Can the combination of real-time monitoring and condition based maintenance justify reduced pressure testing? Does testing too frequently result in a shorter BOP operational lifespan?

Please provide supporting reasons and data for your responses.

(5) Increased Severing Capability

The BSEE is proposing a variety of requirements that will increase the likelihood that a BOP will be able to severe a drill string in an emergency situation to shut-in the well and prevent a catastrophic blowout.[4] However, there are a variety of components in the drill string (*e.g.,* drill collars) that cannot be severed using technology that is currently being used in offshore operations. Accordingly, BSEE is considering including the following requirement in § 250.734 of the final rule for subsea BOPs:

You must install technology that is capable of severing any components of the drill string (excluding drill bits). You must install this technology within 10 years from the publication of the final rule.

Such a severing requirement would provide additional protection against the potential loss of well control by requiring that operators install supplemental technology that ensures all components of a drill string, including those components that cannot be sheared with current shear rams, could be severed in an emergency to allow the well to be safely shut-in. The operator would have the flexibility to develop or select the technology and equipment to accomplish this performance-based requirement. The BSEE is aware of at least one candidate technology that is currently being evaluated and believes that other innovative or improved technologies would be developed to accomplish this objective, if such a requirement is adopted in the final rule. The industry has demonstrated that it has the financial resources and technical expertise to develop the innovative technology needed to explore and produce oil and gas resources in challenging deepwater and HTHP environments.[5]

In addition, BSEE is considering whether to also make this type of requirement applicable to surface BOPs in § 250.733 in the final rule. The BSEE is requesting comments on the following issues:

—Please comment on whether BSEE should include a severing provision for subsea BOPs in the final rule, as previously described. If BSEE does so, please address whether that requirement should also apply to surface BOPs, given the number of blowouts involving surface stacks.
—What incentives or other actions could be used to assist in the development and implementation of this technology? What should BSEE's role, if any, be in this development process?
—If BSEE includes a severing provision in the final rule, what would be an appropriate effective date for such a requirement? In particular, please comment on whether 10 years would be appropriate to develop technology that could meet the severing requirement, or whether the timeframe for development of such technology and for compliance with the requirement could be shortened (*e.g.,* to 5 years).

Please provide an explanation and data with your responses.

The BSEE is unable to locate any applicable comparative cost estimates or other data to estimate the labor or other costs to industry that would be associated with the installation of technology capable of severing any components of the drill string (excluding drill bits). Also, assessing or quantifying the potential benefits that could arise from the reduction of risks over the 10-year period covered by the economic analysis for this proposed rule would require additional data. Accordingly, BSEE is also requesting comments on the following issues associated with this potential severing provision:

—Please provide comments on any costs related to the development and installation of technology that would be needed to satisfy this type of performance-based requirement within 10 years. Assuming the final rule includes such a provision, how should BSEE include such costs in the final economic analysis for this rulemaking, given that the analysis uses a 10-year period to estimate all costs and benefits?
—What would be the costs of developing and installing appropriate technology to meet such a severing requirement in 5 years? If it would not be feasible to comply with this requirement in 5 years, what would be the incremental increase in costs of

[4] *See* recommendations of Offshore Energy Safety Advisory Committee, August 2012 meeting, available at: *http://www.bsee.gov/uploadedFiles/BSEE/About_BSEE/Public_Engagement/Ocean_Energy_Safety_Advisory_Committee/OESC%20Recommendations%20August%202012%20Meeting%20Chairman%20Letter%20to%20BSEE%20101512.pdf.*

[5] For example, soon after the *Deepwater Horizon* incident, several of the largest oil companies created the Marine Well Containment Co., and agreed to spend $1billion to develop and build new containment technology for deepwater drilling. *See http://www.npr.org/2011/04/19/135513456/oil-firms-seek-to-prove-they-can-contain-spills.* In addition, BP initiated ''Project 20K''—a major research and development initiative involving Maersk Drilling and other companies—to develop new technologies, within a decade, for drilling safely in deepwater under HPHT conditions. *See http://www.maersk.com/en/the-maersk-group/about-us/maersk-post/2014-5/pushing-technological-boundaries.* Similarly, McMoran has already invested over $1.2 billion in deepwater drilling sites in the GOM and is working with researchers and manufacturers to develop heavy duty BOPs and make other necessary technological advances. *See http://www.forbes.com/sites/christopherhelman/2013/05/08/mcmoran-gives-update-on-davy-jones-the-1-billion-ultradeep-well/; http://www.spe.org/tech/2012/04/high-pressurehigh-temperature-challenges/. See also http://www.shell.com/global/aboutshell/major-projects-2/perdido/unlocking-energy.html* (Shell uses innovative, first-of-its-kind technology to produce ultra-deep *Perdido* well).

any implementation deadline between 5 years and 10 years?

—How much would a severing requirement, whether applicable only to subsea BOPs or to subsea and surface BOPs, reduce the risk or consequences of a blowout? If BSEE includes such a requirement in the final rule, to be effective 10 years after the final rule takes effect, how could BSEE estimate the benefits of such risk reduction given that those benefits would not be realized until after the 10-year economic analysis period used in this proposed rule? If BSEE included such a severing requirement with a shorter time period for compliance (*e.g.,* 5 years from the final rule effective date), how could BSEE estimate the potential risk reduction benefits?

—Please describe any alternative method (other than the potential severing requirement) to protect against the potential loss of well control. Please discuss whether such an alternative would be more or less costly than the proposed requirement.

Please explain your conclusions and provide supporting information.

Appendix

The following appendix will not appear in the Code of Federal Regulations. Appendix A is included in this proposed rule so we may solicit your comments on proposed revisions to an existing form for use in reporting some of the information required in proposed subpart G.

Appendix—Department of the Interior—Form BSEE–0144, ''Rig Movement Notification Report.''

RIG MOVEMENT NOTIFICATION REPORT

U. S. Department of the Interior
Bureau of Safety & Environmental Enforcement

OMB Control Number 1014-NEW
OMB Approval Expires: xx/xx/xxxx

Use this form to report the movement (including skids, stacking, and moving in or out of the OCS) of all rig units include MODUs, platform rigs, snubbing units, wire-line units used for non-routine operations, and coiled tubing units. If the rig is moving from one location to another, you may show this by completing the information for both rig departure and rig arrival on the same form. It is preferred by BSEE that the report information be submitted utilizing the BSEE eWell web based system at https://ewell.BSEE.gov; or you have the option to e-mail or telefax (see page 2 for contact information) to the appropriate BSEE Office(s) at least 72 hours before you move the rig.

GENERAL INFORMATION

Report Date	Lease Operator
Rig Name	Rig Type: Barge ___ Coiled Tubing Unit ___ Drill Ship ___ Jackup ___ Platform ___ Snubbing Unit ___ Semisubmersible ___ Submersible ___ Wire-Line Unit ___
Rig Representative	Rig Telephone Number

RIG ARRIVAL INFORMATION

Rig Arrival Date	Work Scheduled: Drilling ___ Workover ___ Completion ___ TA ___ PA ___ Other (specify) ___________________________________				
Is rig new to OCS? Yes ___ No ___	Location where rig came from: ____				
Well API Number (10 digits)		Well Name	Expected Duration of Well Operations		
Well Surface Location Information	Lease No.	Area Name	Block No.	Latitude *(Optional)*	Longitude *(Optional)*
Structure Location Information *(Optional)*	Is Well Adjacent to Structure? Yes ___ No ___		If Yes, Identify Structure		Distance from Structure
Remarks (Include size and extent of the mooring system and number of lighted and unlighted buoys deployed) *(Optional)*					

RIG DEPARTURE INFORMATION

Rig Departure Date	Well Status: Completed ___ DSI ___ TA ___ PA ___				
Well API Number (10 digits)	Well Name	Is Rig Being Skidded on the Platform? Yes ___ No ___			
Well Surface Location Information	Lease No.	Area Name	Block No.	Latitude *(Optional)*	Longitude *(Optional)*
Area Clearance Information *(Optional)*	Is Area Clear of Obstructions? Yes___ No ___	If No, Explain			
Remarks (Include any significant en route movements) *(Optional)*					

RIG STACKING INFORMATION

Rig Arrival Date			Rig Departure Date		
Manned (warm)	Un-manned (cold)		Location:		
Any modifications, repairs, or construction: Yes ___ No ___	Date of Modifications, repairs, or construction	Area Name	Block No.	Latitude *(Optional)*	Longitude *(Optional)*
Area Clearance Information *(Optional)*	Is Area Clear of Obstructions? Yes___ No ___		If No, Explain		
Remarks (Explain any modifications, repairs, or construction.)					

CERTIFICATION: I certify that the information submitted above is complete and accurate to the best of my knowledge. I understand that making a false statement may subject me to criminal penalties under 18 U.S.C. 1001.

Name and Title: ________________________________ Date: ___________________

BSEE OCS CONTACT INFORMATION			
District/ Region	**Telephone**	**Telefax**	**E-mail Address**
New Orleans District	(504) 734-6740	(504) 734-6741	bsee.new.orleans.district@bsee.gov
Houma District	(985) 853-5884	(985) 879-2738	bsee.houma.district@bsee.gov
Lafayette District	(337) 289-5100	(337) 354-0008	bsee.lafayette.district@bsee.gov
Lake Charles District	(337) 480-4600	(337) 562-2955	bsee.lake.charles.district@bsee.gov
Lake Jackson District	(979) 238-8121	(979) 238-8122	bsee.lake.jackson.district@bsee.gov
Alaska OCS Region	(907) 334-5300	(907) 334-5202	kevin.pendergast@bsee.gov
Pacific OCS Region	(805) 389-7745	(805) 389-7784	john.kaiser@bsee.gov

PAPERWORK REDUCTION ACT of 1995 (PRA) STATEMENT: The PRA (44 U.S.C. 3501 *et seq.*) requires us to inform you that we collect this information to obtain knowledge of equipment and procedures to be used in drilling, sidetracking, completing, reworking, recompleting, and abandoning wells. BSEE uses the information to schedule inspections and verify that equipment and/or procedures are adequate to perform the proposed operations safely. Responses are mandatory (43 U.S.C. 1334). Proprietary data are covered under 30 CFR 250.197. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB Control Number. Public reporting burden for reviewing the instructions, completing and filling out this form is estimated to average 42 minutes per response. This form has been assigned OMB Control Number 1014-NEW. However, this form is also used for activities regulated under 30 CFR 250, subparts D, E, F, P, and Q. Direct comments regarding the burden estimate or any other aspect of this form to the Information Collection Clearance Officer, Bureau of Safety and Environmental Enforcement, 45600 Woodland Road, Sterling, VA 20166.

FORM BSEE-0144 (Mo/Yr – Supersedes all previous versions of this form which may not be used). Page 2 of 2

BILLING CODE 4310–VH–C

VI. Derivation Tables

The following tables are intended to provide information about the derivation of proposed requirements in Subparts A, B, D, E, F, proposed G, P, and Q. These tables provide guidance on the following:

—The destination of various current requirements.

—The organization and content of the proposed revisions.

These tables do not provide definitive or exhaustive guidance, and should be used in conjunction with the section-by-section discussion and regulatory text of this proposed rule.

The following sections in 30 CFR part 250, subparts D, E, F, and Q have either been [Removed and/or Reserved] according to the following table.

Subpart	Removed and/or Reserved in 30 CFR Part 250
D	401, 402, 403, 406, 417, 424, 425, 426, 440 through 451, 466 through 469.
E	502, 506, 515 through 517.
F	602, 606, 615, 617, 618.
Q	1705, 1707 through 1709, 1717.

The proposed rule would make changes as outlined in the following table:

Current regulations section	Proposed rule section	Nature of change
Subpart A		
250.102(b)	250.102(b)	Added reference to new subpart G.
NEW	250.107(a)(3), (a)(4); (e)	Added the use of recognized industry practices and BSEE-issued orders.
250.125(a)(2)	250.125(a)(2)	Revised (2) to reflect the redesignation of 250.292(q).
250.198(h)	250.198(h)	Updated citations in (h)(51), (68), (70); removed the RP and added in its place the Standard in (h)(63); added new (h)(89–94).
250.199(e)	250.199(e)	Updated OMB control numbers and reword, for plain language, the reasons BSEE collects the data. And added paragraphs for APDs, APMs, and Subpart G.

Current regulations section	Proposed rule section	Nature of change
	Subpart B	
250.292(p)	250.292(q)	Redesignated.
NEW	250.292(p)	New section that specifies FSHR requirements within the DWOP.
	Subpart D	
250.400	250.400	Revised section heading and requirements to encompass General Requirements for drilling and clarify that Subpart G has applicable requirements as well.
250.401	250.703	Removed—similar language found in new Subpart G.
250.402	250.720	Removed—similar language found in new Subpart G.
250.403	250.712	Removed—similar language found in new Subpart G.
250.406	250.723	Removed—similar language found in new Subpart G.
250.411	250.411	Revised to separate the diverter and the BOP descriptions; updating citations.
250.413(g)	250.413(g)	Revised to add the phrase ECD.
250.414	250.414	Revised paragraphs (c), (h), (i); added new paragraphs (j) and (k) to help ensure the well's structural integrity and submission of any additional information required by the District Manager.
250.415(a)	250.415(a)	Revised paragraph (a) for casing information in all sections for each casing interval.
250.416	250.416(a), (b); 250.730; 250.731; 250.732.	Revised to remove only the BOP descriptions in the regulatory text and section heading.
250.417	250.713	Removed—similar language found in new Subpart G.
250.418(g)	250.418(g)	Revised to include a description of how far below the mudline the operator proposes to displace cement in the request for approval; revised citation.
250.420	250.420	Revised the introductory paragraph to include applicable casing and cementing requirements in Subpart G; added new paragraph (a)(6) to require adequate centralization to ensure proper cementation; added new paragraph (b)(4) requiring District Manager approval before installing a different casing than what was approved in the APD; modified paragraph (c) requiring the use of a weighted fluid.
250.421	250.421(b) and (f)	Revised paragraph (b) so casing would have to be set immediately and set above the encountered zone, even if it is before the planned casing point if oil or gas or unexpected formation pressure arises. Revised paragraph (f) to no longer allow liners to be installed as conductor casing.
250.423	250.423	Revised the section heading and removed the pressure testing and negative pressure testing requirements; added clarification about latching mechanisms. Edited the remaining paragraphs of 250.423 for organization.
250.423(a) and (c)	250.721	Removed—similar language found in new Subpart G.
250.424	250.722	Removed—similar language found in new Subpart G.
250.425	250.721	Removed—similar language found in new Subpart G.
250.426	250.746	Removed—similar language found in new Subpart G.
250.427(b)	250.427(b)	Revised paragraph (b) to clarify that operators must maintain two drilling margins.
250.428	250.428	Revised paragraphs (b) through (d). Paragraph (b) requires 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; paragraph (c) clarifies requirements when there is any indication of an inadequate cement job; and paragraph (d) clarifies that if there is an inadequate cement job, the District Manager has to review and approve all remedial actions; that the changes to the well program are reviewed, approved, and certified by a PE; and any other requirements of the District Manager. New paragraph (k) adds requirements concerning the use of values on drive pipe during cementing operations.
250.440	250.730	Removed—similar language found in new Subpart G.
250.441	250.733; 250.735	Removed—similar language found in new Subpart G.
250.442	250.734	Removed—similar language found in new Subpart G.
250.443	250.734; 250.735	Removed—similar language found in new Subpart G.
250.443(c) and (d)	250.733	Removed—similar language found in new Subpart G.
250.444	250.736	Removed—similar language found in new Subpart G.
250.445	250.736	Removed—similar language found in new Subpart G.
250.446	250.739	Removed—similar language found in new Subpart G.
250.447	250.737	Removed—similar language found in new Subpart G.
250.448	250.737	Removed—similar language found in new Subpart G.
250.449	250.737	Removed—similar language found in new Subpart G.
250.450	250.746	Removed—similar language found in new Subpart G.
250.451	250.738	Removed—similar language found in new Subpart G.
250.456(k)	250.456(j)	Redesignated.

Current regulations section	Proposed rule section	Nature of change
250.456(j)	250.720	Removed—similar language found in new Subpart G.
NEW	250.462	New section heading and requirements to demonstrate deepwater well containment.
250.462	250.710 and 250.711	Removed heading and requirements for well- control drills—similar language found in new Subpart G.
250.465(b)(3)	250.465(b)(3)	This paragraph was revised to update the citation for the EOR form, BSEE–0125.
250.466	250.740	Removed—similar language found in new Subpart G.
250.467	250.741	Removed—similar language found in new Subpart G.
250.468(a)	250.742	Removed—similar language found in new Subpart G.
250.468(b) and (c)	250.743	Removed—similar language found in new Subpart G.
250.469	250.745	Removed—similar language found in new Subpart G.
Subpart E		
250.500	250.500	Revised section heading and requirements to encompass General Requirements and direct compliance with new Subpart G where applicable.
250.502	250.723	Removed—similar language found in new Subpart G.
250.506	250.710	Removed—similar language found in new Subpart G.
250.514(d)	250.720	Removed—similar language found in new Subpart G.
250.515	250.731; 250.732	Removed—similar language found in new Subpart G.
250.516	250.730; 250.733; 250.734; 250.735; 250.736.	Removed—similar language found in new Subpart G.
250.517	250.711; 250.737, 250.738, 250.739; 250.746.	Removed—similar language found in new Subpart G.
250.518	250.518(e), (f)	Removed paragraph (b) and redesignated the remaining paragraphs. Added new paragraphs (e) and (f) to add API Spec. 11D1, packer and bridge plug requirements, and a description of calculations of packer setting depth.
250.518(b)	250.722	Redesignated and revised to include additional requirements for prolonged operations.
Subpart F		
250.600	250.600	Revised section heading and requirements to encompass General Requirements and direct compliance with new Subpart G where applicable.
250.602	250.723	Removed—similar language found in new Subpart G.
250.606	250.710	Removed—similar language found in new Subpart G.
250.614(d)	250.720	Removed—similar language found in new Subpart G.
250.615	250.731; 250.732	Removed—similar language found in new Subpart G.
250.616(a) through (e)	250.730; 250.733; 250.734; 250.735; 250.736.	Removed—similar language found in new Subpart G.
250.616(f) through (h)	250.616(a) through (c)	Redesignated with no changes made to regulatory text.
250.617	250.711; 250.737; 250.746	Removed—similar language found in new Subpart G.
250.618	250.739	Removed—similar language found in new Subpart G.
250.619	250.619	Removed paragraph (b) and redesignated the section. Added new paragraphs (e) and (f) to add packers and bridge plug requirements, API Spec. 11D1, and a description of calculations of packer setting depth.
250.619(b)	250.722	Redesignated and revised to include additional requirements for prolonged operations.
New Subpart G		
General requirements		
NEW	250.700	New section describing what operations and equipment are subject to the requirements.
250.408	250.701	Similar language pertaining to alternative procedures or equipment.
250.409	250.702	Similar language pertaining to departures.
250.401	250.703	Similar language containing requirements to keep wells under control.
Rig Requirements		
250.462; 250.506; 250.606	250.710	Similar language was revised and incorporated into this section about instructions for rig personnel.
250.462; 250.517; 250.617; 250.1707.	250.711	Similar language was revised and incorporated into this section about well-control drills.
250.403	250.712	Similar language was revised and incorporated into this section about rig movement notifications.
250.417	250.713	Similar language was revised and incorporated into this section about MODUs or lift boat requirements for well operations.

Current regulations section	Proposed rule section	Nature of change
NEW	250.714	New section about dropped objects plans.
NEW	250.715	New section about GPS for MODUs and jack-ups.
	Well Operations	
250.402; 250.456(j); 250.514(d); 250.614(d); 250.1709.	250.720	Similar language was revised and incorporated into this section about securing a well.
250.423(a), (c); 250.425	250.721	Similar language was revised and incorporated into this section about pressure testing casing and liners.
250.424; 250.518; 250.619	250.722	Similar language was revised and incorporated into this section pertaining to prolonged well operations.
250.406; 250.502; 250.602	250.723	Similar language from 250.406, 250.502, and 250.602 was revised and incorporated into this section relating to safety measures on a platform producing wells or other hydrocarbon flow.
NEW	250.724	New section relating to real-time monitoring requirements.
	Blowout Preventer (BOP) System Requirements	
250.416; 250.440; 250.516; 250.616(a) through (e); 250.1706.	250.730	Similar language was revised and incorporated into this section about general requirements for BOP systems and their components.
250.416; 250.515; 250.615; 250.1705.	250.731	Similar language was revised and incorporated into this section about submittal requirements for information about BOP systems and their components.
250.416; 250.515; 250.615; 250.1705.	250.732	Similar language was revised and incorporated into this section relating to third-party information for BOP systems and their components.
250.441; 250.443(c), (d); 250.516; 250.616(a) through (e); 250.1706.	250.733	Similar language was revised and incorporated into this section and new language was added relating to requirements for a surface BOP stack.
250.442; 250.443(c), (d); 250.516; 250.616(a) through (e); 250.1706.	250.734	Similar language was revised and incorporated into this section and new language was added relating to requirements for a subsea BOP system.
250.441; 250.443; 250.516; 250.616; 250.1706.	250.735	Similar language was revised and incorporated to this section and new language was added relating to equipment and systems all BOPs must have.
250.444; 250.445; 250.516; 250.616(a) through (e); 250.1707.	250.736	Similar language was revised and incorporated into this section pertaining to requirements for choke manifolds, kelly valves, inside BOPs, and drill string safety valves.
250.447; 250.448; 250.449; 250.517; 250.617; 250.1707.	250.737	Added new language and similar language was revised and incorporated into this section relating to BOP system testing requirements.
250.451 and 250.517	250.738	Added new language and similar language was revised and incorporated into this section for situations arising involving BOP equipment or systems.
250.446; 250.517; 250.618; 250.1708.	250.739	Similar language was revised and incorporated into this section pertaining to BOP maintenance and inspection requirements.
	Records and Reporting	
250.466	250.740	Redesignated and revised the types of records to keep.
250.467	250.741	Redesignated and added records relating to real-time monitoring data.
250.468(a)	250.742	Redesignated.
250.468(b) and (c)	250.743	Redesignated and revised to include more requirements for the well activity reporting.
250.465; 250.1712; 250.1717	250.744	Redesignated and revised to include additional end of operation reporting requirements.
250.469	250.745	Redesignated and revised to update references.
250.426; 250.450; 250.517; 250.617; 250.1707.	250.746	Similar language was revised and incorporated into this section pertaining to record-keeping for casing, liner, and BOP tests.
	Subpart P	
250.1612	250.1612	Revised to update references.
	Subpart Q	
250.1703	250.1703	Revised paragraph (b) to have new packers and bridge plug requirements, including API Spec. 11D1. Revised paragraph (e); Redesignated existing paragraph (f) as (g); and added a new paragraph (f) to follow the applicable requirements of Subpart G.
250.1704	250.1704	Revised paragraphs (g) and added new paragraph (h) about APMs and EORs.
250.1705	250.731, 250.732	Removed—similar language found in new Subpart G.

Current regulations section	Proposed rule section	Nature of change
250.1706(a) through (e)	250.730; 250.733, 250.734, and 250.735.	Removed—similar language found in new Subpart G.
250.1706(f) through (h)	250.1706(a) through (c)	Revised the section heading; redesignated.
250.1707	250.711, 250.736, 250.737, 250.746.	Removed—similar language found in new Subpart G.
250.1708	250.739	Removed—similar language found in new Subpart G.
250.1709	250.720	Removed—similar language found in new Subpart G.
250.1715(a)(3)(iii)(B)	250.1715(a)(3)(iii)(B)	Added the word "casing."
250.1717	250.744	Removed—similar language found in new Subpart G.
250.1721(g)	250.744	Removed—similar language found in new Subpart G.
250.1721(h)	250.1721(g)	Redesignated and text remains unchanged.

VII. Procedural Matters

Regulatory Planning and Review (Executive Orders (E.O.) 12866 and 13563))

E.O. 12866 provides that the Office of Information and Regulatory Affairs (OIRA) in the OMB will review all significant rules. To determine if this proposed rulemaking is a significant rule, BSEE had an outside contractor prepare an economic analysis to assess the anticipated costs and potential benefits of the proposed rulemaking. The following discussion summarizes the economic analysis; a complete copy of the economic analysis can be viewed at *www.Regulations.gov* (use the keyword/ID ''BSEE–2015–0002'').

Changes to Federal regulations must undergo several types of economic analyses. First, E.O.s 12866 and 13563 direct agencies to assess the costs and benefits of regulatory alternatives and, if regulation is necessary, to select a regulatory approach that maximizes net benefits (including potential economic, environmental, public health, and safety effects; distributive impacts; and equity). 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 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:

—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'');

—Creates serious inconsistency or otherwise interferes with an action taken or planned by another agency;

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

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

The BSEE has determined that the proposed rule is a significant rulemaking within the definition of E.O. 12866 because the estimated annual costs or benefits would exceed $100 million in at least 1 year of the 10-year analysis period. Accordingly, OMB has reviewed this proposed regulation.

1. *Need for Regulation*

As previously explained, BSEE has identified a need to amend the existing well-control regulations to ensure that oil and gas operations on the OCS are conducted in a safe and environmentally responsible manner. In particular, BSEE considers the proposed rule necessary to reduce the likelihood of any oil or gas blowout, which can lead to the loss of life, serious injuries, and harm to the environment. As was evidenced by the *Deepwater Horizon* incident (which began with a blowout at the Macondo well) on April 20, 2010, blowouts can result in catastrophic consequences.[6] The government and industry conducted multiple investigations to determine the cause of the *Deepwater Horizon* incident; many of these investigations identified BOP performance as a concern. The 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 enhance safety and environmental protection of offshore operations by improving BOP performance.

As the agency charged with oversight of offshore operations conducted on the OCS, BSEE seeks to improve safety and mitigate risks associated with such operations. After careful consideration of the various investigations conducted after the *Deepwater Horizon* incident and industry's responses to the incident, BSEE has determined that the requirements contained in this proposed rule are critical to address risks associated with offshore operations. BSEE has determined that the well-control regulations needed to be updated to incorporate some of these recommendations. Other recommendations are being studied for consideration in future rulemakings.

The proposed rule would create a new Subpart G in 30 CFR part 250 to consolidate requirements for drilling, completion, workover, and decommissioning operations. Consolidating the requirements would improve efficiency and consistency of the regulations and allow for flexibility in future rulemakings. The proposed rule would also revise provisions in Subparts D, E, F, and Q of part 250 to address concerns raised in the investigations, internally within BSEE, and at the public forum. Finally, the proposed rule would incorporate API Standard 53 to ensure better BOP operability and more robust regulatory oversight.

2. *Alternatives*

The BSEE has considered three regulatory alternatives:

(1) Promulgate the requirements contained within the proposed rule, including increasing the BOP testing frequency for workover and decommissioning operations from the current requirement of once every 7 days to the proposed requirement of

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

once every 14 days. The following chart identifies the BOP testing changes related to Alternative 1:

BOP PRESSURE TESTING

Operation	Current testing frequency	Proposed testing frequency
Drilling/Completions	Once every 14 days	Once every 14 days.
Workover/Decommissioning	Once every 7 days	Once every 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 testing changes related to Alternative 2:

BOP PRESSURE TESTING

Operation	Current testing frequency	Proposed testing frequency (alternative 1)	Alternative 2 testing frequency
Drilling/Completions	Once every 14 days	Once every 14 days	Once every 21 days.
Workover/Decommissioning	Once every 7 days	Once every 14 days	Once every 21 days.*

* Includes change from current 7 days to proposed 14 days

(3) Take no regulatory action and continue to rely on existing well-control regulations in combination with permit conditions, DWOPs, operator prudence, and industry standards.

By taking no regulatory action, BSEE would leave unaddressed most of the concerns and recommendations that were raised [7] regarding the safety of offshore oil and gas operations and the potential for another event with consequences similar to those of the *Deepwater Horizon* incident.

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

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

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

3. Economic Analysis

The BSEE's economic analysis evaluated the expected impacts of the proposed rule compared with the baseline. The baseline refers to current industry practice in accordance with existing regulations, industry permits, DWOPs, and industry standards with which operators already comply.[8] Impacts that exist as part of the baseline were not considered costs or benefits of the proposed rule. Thus, the cost analysis evaluates only activities and capital investments required by the proposed rule that represent a change from the baseline. These estimated compliance costs are discussed more specifically in the associated full initial regulatory impact analysis (RIA), which can be viewed at *www.regulations.gov* (use the keyword/ID ''BSEE–2015–0002'').

The analysis covers 10 years (2015 through 2024) to ensure it encompasses the significant costs and benefits likely to result from this proposed rule. A 10-year 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. It is very difficult to predict, plan, or project costs associated with technological innovation due to unknown technological or business constraints that could drive a product into mainstream adoption or into obsolescence. The regulated community itself has difficulty conducting business modeling beyond a 10-year time frame. Over time, the costs associated with a particular new technology may drop because of various supply and demand factors, causing the technology to be more broadly adopted. In other cases, an existing technology may be replaced by a lower-cost alternative as business needs may drive technological innovation. Extrapolating costs and benefits beyond this 10-year time frame would produce more ambiguous results and therefore be disadvantageous in determining actual costs and benefits likely to result from this proposed rule. The BSEE concluded that this 10-year analysis period provides the best overall ability to forecast reliable costs and benefits likely to result from this proposed rule. When summarizing the costs and benefits, we present the estimated annual effects, as well as the 10-year discounted totals using discount rates of 3 and 7 percent, per OMB Circular A–4, ''Regulatory Analysis.''

The BSEE welcomes comments on this analysis, including potential sources of data or information on the costs and benefits of this proposed rule. The BSEE quantified and monetized the

[7] *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*; National Academy of Engineering* final report, *Macondo Well-Deepwater Horizon Blowout,* December 14, 2011*;* BSEE public offshore energy safety forum, May 22, 2012.

[8] 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.

costs, using 2013 data, of all the provisions in the proposed rule determined to result in a change compared to the baseline, including:xs112

—Additional information in the description of well-drilling design criteria;
—Additional information in the drilling prognosis;
—Prohibition of a liner as conductor casing;
—Additional capping stack testing requirements;
—Additional information in the APM for installed packers;
—Additional information in the APM for pulled and reinstalled packers;
—Rig movement reporting;
—Fitness requirements for MODUs and lift boats;
—Foundation requirements for MODUs and lift boats;
—Monitoring of well operations with a subsea BOP;
—Additional documentation and certification requirements for BOP systems and system components;
—Additional information in the APD, APM, or other submittal for BOP systems and system components;
—Submission of a Mechanical Integrity Assessment Report by a BSEE-approved verification body;
—New surface BOP system requirements;
—New subsea BOP system requirements;
—New surface accumulator system requirements;
— Chart recorders;
— Notification and procedures requirements for testing of surface BOP systems;
— Alternating BOP control station function testing;
— ROV intervention function testing; autoshear, deadman, and EDS function testing on subsea BOPs;
— Approval for well-control equipment not covered in Subpart G;
— Breakdown and inspection of BOP system and components;
— Additional recordkeeping for real-time monitoring; and
— Industry familiarization with the new rule.

The BSEE estimated the benefits derived from time savings associated with § 250.737(d)(10) of the proposed rule and the benefits derived from the reduction in oil spills and fatalities using the incident-reducing potential of the proposed rule as a whole. The largest time savings benefits would result from proposed § 250.737 (d)(10), which would streamline the BOP function testing criteria and increase the intervals between this testing. Although we also consider benefits from potential reductions in oil spills and reduced fatalities, the time savings benefits of the proposed rule result in benefits greater than the costs of the rule to the extent that those costs could be quantified. In other words, based upon existing available data, the proposed rule is cost-beneficial when only the benefits resulting from time savings are considered.[9]

The same is true of Alternative 2. A larger time savings benefit would result from changing the BOP pressure testing interval for workover and decommissioning from 7 days to 14 days plus increasing the BOP pressure testing interval for all operations (including drilling, completions, workovers, and decommissioning) from 14 days to 21 days. This alternative would result in additional time savings to industry by decreasing the number of required tests per year for operators. This time savings would result in greater net benefits to operators.

We did not, however, include reduced trip time to perform BOP testing in the calculations of savings for Alternative 2.[10] 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 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 benefits from this alternative. BSEE requests comments and data on both of these issues to assist in the assessment of the overall benefits of this alternative.

The proposed rule also would reduce the probability of oil spills, and the provisions with the highest costs to industry (such as real-time monitoring of well operations and alternating BOP control station function testing) will have the largest impact on reducing the risk of spills. If the proposed rule reduces the risk of incidents, benefits would result from the avoided costs associated with oil spills related to personal injuries, natural resource damages, lost hydrocarbons, spill containment and cleanup, and lost recreational use and lost profits from commercial fishing. The magnitude of these benefits, however, is dependent on the effectiveness of the proposed rule in reducing the number of incidents, which is uncertain.

To estimate the potential benefits of the proposed rule associated with reducing the risk of incidents, we examined historical data from the BSEE oil spill database, which contains information for spills greater than 10 barrels of oil for the GOM and Pacific regions. Based upon an analysis of the BSEE oil spill database during the period between 1964 and 2010, BSEE identified 27 blowouts associated with oil spills greater than 10 barrels[11] and used this data within the economic analysis (*see* the initial RIA for details).[12] Blowouts that resulted in uncontrolled flow of gas, damage to a rig, and/or harm to personnel (but not oil spills over 10 barrels) are not reflected in this analysis.[13] Accordingly, the benefits and the overall risk reduction associated with this proposed rule may be understated. The BSEE is specifically soliciting comments on any data and costs associated with any blowout that did not result in an oils spill greater than 10 barrels, and how to include that information within the economic analysis.

The actual reduction in the risk of oil spills to be achieved by the proposed rule cannot be determined. Although a sensitivity analysis was conducted for levels of risk reduction from 0 to 20 percent, our economic analysis used a 1 percent risk reduction because it

[9] Moreover, the analysis of Alternatives 1 and 2 did not consider potential benefits related to extended equipment life and reduced well control risks arising from fewer pressure tests and fewer trips out of the hole.

[10] 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.

[11] *See http://www.bsee.gov/Inspection-and-Enforcement/Accidents-and-Incidents/Spills/.*

[12] BSEE based the analysis on the historical oil spill database for the period between 1964 and 2010, but recognizes that significant regulatory and technological improvements have taken place since 1964. If BSEE limited the analysis to the period 1988 (when the Department's offshore regulatory program was comprehensively overhauled) through 2010, the potential benefits from this reduction of risk would be substantially greater, due to the impact of the *Deepwater Horizon* costs over such a shorter time period.

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

represents BSEE's best expert judgment of the lower bound of risk reduction that could result from the proposed rule.[14] We multiplied the annual number of spilled barrels of oil (the total number of barrels spilled in the incidents divided by 46.945 years) by 1 percent to estimate the expected annual reduction in barrels of oil spilled associated with the proposed rule.

We then multiplied the annual reduction in spilled barrels of oil by the social and private cost of a spilled barrel of oil, which is estimated at $3,599 per barrel. This estimate was derived from the Bureau of Ocean Energy Management (BOEM) ''Economic Analysis Methodology for the Five Year OCS Oil and Gas Leasing Program for 2012–2017'' (2012) (the BOEM Case Study),[15] and includes costs associated with natural resource damages, the value of lost hydrocarbons, and spill cleanup and containment.[16] We used a natural resource damage cost of $642 per barrel and a cleanup and containment cost of $2,857 per barrel as estimated for the GOM in the BOEM Case Study. Consistent with the BOEM Case Study, we used a value of lost hydrocarbons per barrel of $100. The BSEE recognizes the uncertainty associated with projecting the price of oil during the 10-year period of analysis and thus includes a sensitivity analysis in the initial RIA for the price of oil.

In addition to the time savings and risk reduction benefits, the proposed rule has other benefits. Due to difficulties in measuring and monetizing these benefits, BSEE does not offer a quantitative assessment of them. The BSEE has used a conservative approach in the valuation of an oil spill, including only selected costs of such a spill. For example, although the analysis captures the environmental damage associated with a spill, the analysis is limited because it only considers the environmental amenities that researchers could identify and monetize. Therefore, the resulting benefits of avoiding 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.

Exhibit 1 displays the net benefits of the proposed rule under the assumption that the reduction in the risk of incidents is 1 percent. Although the analysis presents these benefit estimates based on our lower bound assumption of potential risk reduction, there is uncertainty around the level of risk reduction the proposed rule would actually achieve. Accordingly, it is reasonably possible that the actual benefits realized from the reductions in spill incidents will be different from those assessed in this analysis. Nonetheless, as discussed above, the proposed rule is cost-justified on the basis of time savings alone.

EXHIBIT 1—NET BENEFITS

[At a 1-percent risk reduction from the proposed rule][1]

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

[1] Totals may not add because of rounding.

4. Sensitivity Analysis

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

(a) The level of risk reduction of oil spills achieved by the proposed rule;

(b) The level of risk reduction of fatalities achieved by the proposed rule; and

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

Exhibit 2 presents the total 10-year benefits and net benefits under a range of possible annual risk reduction levels for oil spills from 0 to 20 percent. The

[14] 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,'' American Bureau of Shipping and ABSG Consulting, under BSEE contract M11PC00027 (June 2013); ''*Deepwater Horizon* Blowout Preventer Failure Analysis: Report to the U.S. Chemical Safety and Hazard Investigation Board,'' Engineering Services (2014). Given this accumulated knowledge of failure likelihoods, and analysis of how those likelihoods would be reduced by the proposed rule, BSEE has determined that 1 percent is a reasonable lower-bound of risk reduction that could occur as a result of the proposed rule.

[15] The BOEM Case Study presents seven separate cost categories to estimate the impact of a catastrophic spill, including natural resource damages, as well as impacts on recreation and commercial fishing. The BOEM Case Study is 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.*

[16] 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 reflects data from the *Deepwater Horizon* incident.

proposed rule is expected to have positive net benefits for the full range of risk reduction levels.

In addition to the time savings and the prevention of oil spills, the proposed rule is anticipated to reduce the risk of fatalities to rig workers. The oil and gas extraction industry is characterized by a relatively small percentage of the national workforce, but with a fatality rate that is higher than the rate for most industries.

EXHIBIT 2—NET BENEFITS UNDER DIFFERENT RISK REDUCTION LEVELS [1]

Annual risk reduction (%)	Annual benefits	Benefits (7% discounting)	Benefits (3% discounting)	Net benefits (undiscounted)	Net benefits (7% discounting)	Net benefits (3% discounting)
	Total 10-Year					
0	$0	$1,053,537,231	$1,279,530,426	$616,752,910	$413,652,394	$516,132,695
1	3,988,977	1,081,554,137	1,313,557,210	656,642,682	441,669,301	550,159,479
2	7,977,954	1,109,571,044	1,347,583,994	696,532,453	469,686,207	584,186,263
3	11,966,931	1,137,587,950	1,381,610,778	736,422,225	497,703,113	618,213,047
4	15,955,909	1,165,604,856	1,415,637,562	776,311,996	525,720,019	652,239,832
5	19,944,886	1,193,621,762	1,449,664,346	816,201,768	553,736,926	686,266,616
6	23,933,863	1,221,638,669	1,483,691,131	856,091,539	581,753,832	720,293,400
7	27,922,840	1,249,655,575	1,517,717,915	895,981,311	609,770,738	754,320,184
8	31,911,817	1,277,672,481	1,551,744,699	935,871,082	637,787,644	788,346,968
9	35,900,794	1,305,689,387	1,585,771,483	975,760,854	665,804,551	822,373,752
10	39,889,771	1,333,706,294	1,619,798,267	1,015,650,625	693,821,457	856,400,537
11	43,878,749	1,361,723,200	1,653,825,051	1,055,540,397	721,838,363	890,427,321
12	47,867,726	1,389,740,106	1,687,851,836	1,095,430,168	749,855,269	924,454,105
13	51,856,703	1,417,757,012	1,721,878,620	1,135,319,939	777,872,176	958,480,889
14	55,845,680	1,445,773,919	1,755,905,404	1,175,209,711	805,889,082	992,507,673
15	59,834,657	1,473,790,825	1,789,932,188	1,215,099,482	833,905,988	1,026,534,457
16	63,823,634	1,501,807,731	1,823,958,972	1,254,989,254	861,922,894	1,060,561,242
17	67,812,611	1,529,824,637	1,857,985,756	1,294,879,025	889,939,801	1,094,588,026
18	71,801,589	1,557,841,544	1,892,012,541	1,334,768,797	917,956,707	1,128,614,810
19	75,790,566	1,585,858,450	1,926,039,325	1,374,658,568	945,973,613	1,162,641,594
20	79,779,543	1,613,875,356	1,960,066,109	1,414,548,340	973,990,519	1,196,668,378

[1] For Alternative 1, the proposed rule.

Exhibit 3 presents the resulting total 10-year fatality risk reduction benefit across a range of risk reduction values from 0 to 20 percent. The exhibit also 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 analysis presented above (assuming a 1 percent risk reduction in the probability of incidents involving oil spills). The benefits of occupational risk reduction are usually measured using the value of a statistical life (VSL). The BSEE used a VSL of $8.4 million to estimate the avoided costs associated with a reduction in the fatality rate [17] (*see* initial RIA for details of VSL calculations).

EXHIBIT 3—MONETIZED BENEFITS FROM AVERTED FATALITIES W/NET BENEFITS [1]

Fatality risk reduction (%)	Fatality risk reduction benefit	Net benefits of proposed rule without fatality risk reduction (at a 1-percent risk reduction)	Net benefits of proposed rule with fatality risk reduction (at a 1-percent risk reduction)		
	Undiscounted	Undiscounted	Undiscounted	3% Discounting	7% Discounting
	Total 10-year				
0	$0	$656,642,682	$656,642,682	$550,159,479	$441,669,301
1	269,142	656,642,682	656,911,824	550,389,063	441,858,335
2	538,285	656,642,682	657,180,967	550,618,647	442,047,369
3	807,427	656,642,682	657,450,109	550,848,231	442,236,403
4	1,076,569	656,642,682	657,719,251	551,077,814	442,425,438
5	1,345,712	656,642,682	657,988,393	551,307,398	442,614,472
6	1,614,854	656,642,682	658,257,536	551,536,982	442,803,506
7	1,883,996	656,642,682	658,526,678	551,766,566	442,992,541

[17] Between 1964 and 2010, there were 27 blowouts with oil spills greater than 10 barrels. Only two of these events resulted in fatalities: the 1984 blowout and the 2010 *Deepwater Horizon* incident that resulted in 4 and 11 fatalities, respectively. Based on the 47-year period from 1964 to 2010, the average number of fatalities was approximately 0.320 annually (15/46.945). Using a VSL of $8,423,301, the average value of fatalities is $2,691,423 per year (0.320 × $8,423,301). Therefore, each 1 percent reduction in the risk of a fatality results in a risk reduction benefit of $26,914 (1 percent × $2,691,423). Note that this calculation likely understates the benefits associated with fatality risk reduction because blowouts that did not result in an oil spill greater than 10 barrels were not part of the database used for this analysis. Previous MMS studies indicate a total of 126 blowouts during drilling operations on the OCS between 1971 and 2006. These blowouts resulted in 26 fatalities, 63 injuries, damage to facilities and equipment, and the release of hydrocarbons. Accounting for any additional fatalities would increase the fatality risk reduction benefits.

EXHIBIT 3—MONETIZED BENEFITS FROM AVERTED FATALITIES W/NET BENEFITS [1]—Continued

Fatality risk reduction (%)	Fatality risk reduction benefit	Net benefits of proposed rule without fatality risk reduction (at a 1-percent risk reduction)	Net benefits of proposed rule with fatality risk reduction (at a 1-percent risk reduction)		
	Undiscounted	Undiscounted	Undiscounted	3% Discounting	7% Discounting
	Total 10-year				
8	2,153,139	656,642,682	658,795,820	551,996,150	443,181,575
9	2,422,281	656,642,682	659,064,963	552,225,734	443,370,609
10	2,691,423	656,642,682	659,334,105	552,455,318	443,559,644
11	2,960,565	656,642,682	659,603,247	552,684,901	443,748,678
12	3,229,708	656,642,682	659,872,390	552,914,485	443,937,712
13	3,498,850	656,642,682	660,141,532	553,144,069	444,126,746
14	3,767,992	656,642,682	660,410,674	553,373,653	444,315,781
15	4,037,135	656,642,682	660,679,817	553,603,237	444,504,815
16	4,306,277	656,642,682	660,948,959	553,832,821	444,693,849
17	4,575,419	656,642,682	661,218,101	554,062,405	444,882,884
18	4,844,562	656,642,682	661,487,244	554,291,988	445,071,918
19	5,113,704	656,642,682	661,756,386	554,521,572	445,260,952
20	5,382,846	656,642,682	662,025,528	554,751,156	445,449,986

[1] For Alternative 1, the proposed rule.

As an additional sensitivity analysis, we estimated the net benefits of the proposed rule for different assumptions regarding the value of lost hydrocarbons. In the analysis presented above, BSEE used $100 per barrel for the value of lost hydrocarbons in the event of a spill. To reflect the fluctuations in the price of a barrel of oil that may occur during the 10-year analysis period, we also estimated the net benefits of the proposed rule for two alternative price scenarios: $50/barrel and $130/barrel. Exhibit 4 presents the results, which indicate that the price of oil has a very limited impact on the net benefits of the proposed rule.

EXHIBIT 4—NET BENEFITS UNDER THREE OIL PRICE SCENARIOS

[At a 1-percent risk reduction from the proposed rule]

Year	$50/barrel	$100/barrel	$130/barrel
	(2012 dollars/year)		
1. 2015	($10,928,596)	($10,873,805)	($10,840,931)
2. 2016	76,502,597	76,557,387	76,590,262
3. 2017	76,502,597	76,557,387	76,590,262
4. 2018	76,502,597	76,557,387	76,590,262
5. 2019	76,502,597	76,557,387	76,590,262
6. 2020	55,002,597	55,057,387	55,090,262
7. 2021	76,502,597	76,557,387	76,590,262
8. 2022	76,502,597	76,557,387	76,590,262
9. 2023	76,502,597	76,557,387	76,590,262
10. 2024	76,502,597	76,557,387	76,590,262
Undiscounted 10-year total	656,094,777	656,642,682	656,971,425
10-Year Total with 3% discounting	549,692,105	550,159,479	550,439,903
10-Year Total with 7% discounting	441,284,475	441,669,301	441,900,196
10-year Average	65,609,478	65,664,268	65,697,142
Annualized with 3% discounting	64,440,684	64,495,474	64,528,349
Annualized with 7% discounting	62,828,982	62,883,772	62,916,646

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

E.O. 13563 reaffirms the principles of E.O. 12866 while calling for improvements in the Nation's regulatory system to promote predictability, to reduce uncertainty, and to use the best, most innovative, and least burdensome tools for achieving regulatory ends. The E.O. directs agencies to consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the public where these approaches are relevant, feasible, and consistent with regulatory objectives. The E.O. 13563 emphasizes further that regulations must be based on the best available science and that the rulemaking process must allow for public participation and an open exchange of ideas. The BSEE engineers and technical staff have and will continue to work to ensure that this proposed rulemaking is based on sound engineering principles and considers options identified through research, coordination with standards-development organizations, and interaction with the OCS industry. Thus, we have developed this rule in a manner consistent with these requirements.

In addition, BSEE is considering whether to use probabilistic risk assessment methodology—including event trees, statistical information (*e.g.,* failure rates of valves), probabilities, uncertainties, and assumptions—that potentially could help inform BSEE's final decision on the proposed regulation. Further details about a potential probabilistic risk assessment approach are provided in the initial RIA. The BSEE is interested in the public's views on the potential advantages and disadvantages to development of a probabilistic risk assessment model for this rulemaking. We specifically seek comments on the following issues:

(a) What would be the potential advantages and disadvantages if BSEE were to move to risk-informed decisions in this proposed rule through the use of methods such as probabilistic risk assessments and event trees?

(b) Given that there are a significant number of offshore drilling operations with different types of rig construction and drilling plans, if BSEE were to use event trees in risk reduction assessments, how much detail would such event trees need so that they would be representative of the affected operators and best inform stakeholders and decision makers? Commenters should provide examples of benefits and costs of any suggested level of detail and explain why that detail would be appropriate.

(c) Describe any completed, ongoing or planned activities, not associated with BSEE, that would provide information beneficial to the potential development of a probabilistic risk assessment approach for this rulemaking, including any analyses identifying areas of significant risk or uncertainties. If you do so, provide timelines for the activity, if not already completed; indicate whether the activity will be peer-reviewed; and explain how it could be used in the potential development of a probabilistic risk assessment approach.

(d) Describe any other planned or ongoing data collection efforts that could provide relevant information useful in the potential development of probabilistic risk assessment models for offshore oil and gas activities. If there are no such efforts at this time, how could such a data collection program be developed?

(e) What challenges and concerns would there be to industry providing data to inform and help BSEE decide whether to engage in probabilistic risk assessment modeling for this proposed rule? What are ways that the challenges and concerns could be mitigated?

The BSEE is also requesting comments on other ways to improve this economic analysis. The BSEE is specifically requesting comments on the following issues:

(a) Which provisions of the proposed rule are most, or least, likely to reduce the risk of a well control incident?

(b) For each proposed rule provision:

(1) For what kinds of well control incidents (*e.g.,* hydrocarbon leakage through annulus cement barrier, weather-related incident, collision) would the provision reduce risk?

(2) By what mechanism would the provision reduce risk (*e.g.,* reduction of the rate of failure of a particular technology)?

(c) What risk reduction level (or range of risk reduction levels) would the individual provisions achieve?

Please provide supporting data and studies to support your comments.

Regulatory Flexibility Act

The DOI certifies that this proposed rule is likely to have a significant economic effect on a substantial number of small entities as defined under the Regulatory Flexibility Act, 5 U.S.C. 601 *et seq.* (RFA).

The RFA, at 5 U.S.C. 603, requires agencies to prepare a regulatory flexibility analysis to determine whether a regulation would have a significant economic impact on a substantial number of small entities. Further, under the Small Business Regulatory Enforcement Fairness Act of 1996, 5 U.S.C. 801 (SBREFA), an agency is required to produce compliance guidance for small entities if the rule would have a significant economic impact. For the reasons explained in this section, BSEE believes that this proposed rule would likely have a significant economic impact on a substantial number of small entities and, therefore, a regulatory flexibility analysis is required by the RFA. This Initial Regulatory Flexibility Analysis assesses the impact of this proposed rule on small entities, as defined by the applicable Small Business Administration (SBA) size standards.

1. Description of the Reasons That Action by the Agency Is Being Considered

The BSEE identified a need to amend the existing well-control regulations to improve the capability of the oil and gas industry to ensure that oil and gas operations on the OCS are safe and protect the environment. In particular, BSEE considers the proposed rule necessary to reduce the likelihood of all oil and gas blowouts, which can lead to the loss of life, serious injuries, and harm to the environment. As was evidenced by the *Deepwater Horizon* incident (which began with a blowout at the Macondo well) on April 20, 2010, blowouts can result in catastrophic consequences. Government and industry conducted multiple investigations to determine the cause of the *Deepwater Horizon* incident; many of these investigations identified BOP performance as a concern. The 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 well-control operations, including BOP performance.

The BSEE determined that the well-control regulations needed to be updated to incorporate some of these recommendations while others are being studied for consideration in future rulemakings. The proposed rule would create a new Subpart G in 30 CFR part 250 to consolidate the requirements for drilling, completion, workover, and decommissioning operations. Consolidating these requirements would improve the efficiency and consistency of the regulations and would allow for flexibility in future rulemakings. The proposed rule would also revise existing provisions throughout Subparts A, B, D, E, F, P, and Q of part 250 to address concerns raised in the *Deepwater Horizon* investigations. Finally, the proposed rule would incorporate API Standard 53 to ensure better BOP performance and operability and more robust regulatory oversight.

2. Description and Estimated Number of Small Entities Regulated

Small entities, as defined by the RFA, consist of small businesses, small organizations, and small governmental jurisdictions. We have not identified any small organizations or small government jurisdictions that the rule will impact, so this analysis focuses on impacts to small businesses (hereafter referred to as ''small entities''). A small entity is one that is independently owned and operated and which is not dominant in its field of operation.[18] The definition of small business varies from industry to industry in order to properly reflect industry size differences.

[18] See 5 U.S.C. 601.

The proposed rule would affect operators and holders of Federal oil and gas leases, as well as right-of-way holders, in the OCS. This includes about 130 businesses with active operations. Businesses that operate under this rule fall under the SBA's North American Industry Classification System (NAICS) codes 211111 (Crude Petroleum and Natural Gas Extraction) and 213111 (Drilling Oil and Gas Wells). For these NAICS classifications, a small business is defined as one with fewer than 500 employees. Based on these criteria, approximately 90 (69 percent) of the businesses operating on the OCS are considered small and the rest are considered large businesses. The BSEE considers that a rule has an impact on a ''substantial number of small entities'' when the total number of small entities impacted by the rule is equal to or exceeds 10 percent of the relevant universe of small entities in a given industry. Therefore, BSEE expects that the proposed rule would affect a substantial number of small entities.

The BSEE is using the estimated 130 businesses based on activity at the time this economic analysis was developed. The 130 businesses represent the best assessment of the total businesses operating in this arena at the time the economic analysis was developed. The BSEE recognizes that this number is a dynamic number and can fluctuate; however, BSEE determined that this number of businesses was appropriate for this rulemaking. The BSEE is requesting comments on the use of the active business numbers, and other ways to quantify the changing number of businesses.

3. Description and Estimate of Compliance Requirements

The BSEE has estimated the incremental costs for small operators, lease holders, and right-of-way holders in the offshore oil and natural gas production industry. Costs already incurred as a result of current industry practice in accordance with existing regulations, industry permits, DWOPs, and API industry standards with which operators already comply were not considered as costs of this rule because they are part of the baseline.[19] As described in section 5 below, BSEE considered three alternatives. Alternative 2 results in a time-savings benefit to industry but no additional costs to industry, and thus the costs presented below are the same for Alternatives 1 and 2. We have estimated the costs of the following provisions of the rule:

—Additional information in the description of well drilling design criteria;
—Additional information in the drilling prognosis;
—Prohibition of a liner as conductor casing;
—Additional capping stack testing requirements;
—Additional information in the APM for installed packers;
—Additional information in the APM for pulled and reinstalled packers;
—Rig movement reporting;
—Fitness requirements for MODUs and lift boats;
—Foundation requirements for MODUs and lift boats;
—Monitoring of well operations with a subsea BOP;
—Additional documentation and verification requirements for BOP systems and system components;
—Additional information in the APD, APM, or other submittal for BOP systems and system components;
—Submission by the operator of a Mechanical Integrity Assessment Report completed by a BSEE-approved verification organization;
—New surface BOP system requirements;
—New subsea BOP system requirements;
—New surface accumulator system requirements;
—Chart recorders;
—Notification and procedure requirements for testing of surface BOP systems;
—Alternating BOP control station function testing;
—ROV intervention function testing;
—Autoshear, deadman, and EDS function testing on subsea BOPs;
—Approval for well-control equipment not covered in Subpart G;
—Breakdown and inspection of BOP system and components;
—Additional recordkeeping for real-time monitoring; and
—Industry familiarization with the new rule.

These requirements and their associated costs to the OCS industry and government are presented in the sections below.[20]

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

Section 250.413(g) of the proposed rule would require information on the ECD to be included in the description of the well drilling design criteria. The ECD is an important parameter in avoiding fracturing the formation or compromising the casing shoe integrity, which could lead to erratic pressures and uncontrolled flows (*e.g.,* formation kicks) emanating from a well reservoir during drilling. This information is necessary to better review the well drilling design and drilling program. The requirement to include information on the ECD in the well drilling design criteria would result in an average annual labor cost to industry of $218 per entity.[21]

(b) Additional information in the drilling prognosis.

Section 250.414 of the proposed rule would require the OCS industry to provide additional information in the drilling prognosis. New paragraph (j) would require the drilling prognosis to identify the type of wellhead system to be installed with a descriptive schematic, which should include pressure ratings, dimensions, valves, load shoulders, and locking mechanism, if applicable. The requirement to include additional information in the drilling prognosis (submitted as part of the APD) would result in an average annual labor cost to industry of $54 per entity.[22]

(c) Prohibition of a liner as conductor casing.

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

[19] API standards are developed by industry members and technical experts in open meetings based on a consensus process. They contain the baseline requirements that the industry has deemed necessary to operate in a safe and reliable manner and are often incorporated into commercial contracts between contractors and operators.

[20] Sums presented in the sections below may not equal the sums of the costs identified in this section because of rounding.

[21] We assumed that industry staff (mid-level engineer) would spend one hour per well to include the additional information in the well drilling design criteria. Industry already complies with this new requirement as part of its design practice for most wells drilled. To be conservative, however, we assumed that this requirement would result in a new cost for all wells drilled per year (320). We multiplied the number of industry staff hours per well by the average hourly compensation rate for a mid-level industry engineer ($88.38) and by the average number of wells drilled per year to obtain an average annual labor cost to industry of $28,282 ($1 \times \$88.38 \times 320$). We then divided the average annual labor cost by the number of entities (130) to obtain an average labor cost per entity of $218 ($28,282 ÷ 130).

[22] We assumed that industry staff (a mid-level engineer) would spend 0.25 hours to include the additional information in the drilling prognosis for a well. We multiplied the number of industry staff hours per well by the average hourly compensation rate for a mid-level industry engineer ($88.38) and the average number of wells drilled per year (320) to obtain the average annual labor cost to industry of $7,070 ($0.25 \times \$88.38 \times 320$). We then divided the average annual labor cost by the number of entities (130) to obtain an average annual labor cost per entity of $54 ($7,070 ÷ 130).

This provision would result in an average annual equipment and labor cost to industry of $6,115 per entity.[23]

(d) Additional capping stack testing requirements.

Proposed § 250.462 would address source control and containment requirements. New paragraph (e)(1) would detail requirements for the testing of capping stacks. New requirements include the function testing of all critical components on a quarterly basis and the pressure testing of pressure holding critical components on a bi-annual basis. These new requirements would help ensure that operators are able to contain a subsea blowout. These new testing requirements would result in an average annual equipment and service cost to industry of $615 per entity.[24]

(e) Additional information in the APM for installed packers.

Proposed paragraphs (e) and (f) in § 250.518 would clarify requirements for installed packers and bridge plugs and require additional information in the APM, including descriptions and calculations for determining production packer setting depth. These new requirements would codify existing BSEE policy to ensure consistent permitting. It is expected that operators already comply with the design specifications included in this section because this is the only established industry standard. Thus, the depth setting calculation is the only requirement that would impose a new cost beyond the current baseline. The required calculations would be submitted for every well that is completed where tubing is installed. The requirement to include additional information in the APM would result in an average annual labor cost to industry of $44 per entity.[25]

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

In § 250.619, new paragraphs (e) and (f) would clarify requirements for pulled and reinstalled packers and bridge plugs and would require additional descriptions and calculations in the APM regarding production packer setting depth. These new requirements would codify existing BSEE policy to ensure consistent permitting. It is expected that operators already comply with the design specifications included in this section because this is the only established industry standard. The depth setting calculation is the only requirement that would impose a new cost beyond the current baseline. The required calculations would 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 would result in an average annual labor cost increase to industry of $172 per entity.[26]

(g) Rig movement reporting.

Proposed § 250.712 would list the requirements for reporting movement of rig units to the BSEE District Manager. Paragraph (a) would extend the rig movement reporting requirements to all rig units conducting operations covered under this subpart, including MODUs, platform rigs, snubbing units, wire-line units used for non-routine operations, and coiled tubing units. Paragraphs (c) and (e) are new and would require notification if a MODU or platform rig is to be warm or cold stacked or if a drilling rig would enter or leave the OCS. Paragraph (f) would be revised to clarify that, if the anticipated date for initially moving on or off location were to change by more than 24 hours, an updated Rig Movement Notification Report would be required.

Currently, rig movement reports are only required for drilling operations, but the proposed rule would require operators to submit rig movement reports for other operations as well, including cases when rigs are stacked or would enter or leave the OCS. These changes would 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 would result in an average annual labor cost to industry of $19 per entity.[27]

(h) Fitness requirements for MODUs and lift boats.

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

[23] We estimated that approximately one percent of drilled wells currently have a liner as conductor casing (approximately one percent of 320 wells, or three wells), based on input provided in submittals to BSEE. To calculate the average annual equipment cost, we assumed that the average cost of the casing joints and wellhead per well would be $65,000. We multiplied the equipment cost per well by the number of affected wells to yield an average equipment cost of $195,000 ($65,000 × 3). We assumed that industry staff (rig crew) would spend one day to install the new equipment on a well. We then multiplied the number of industry staff days per well by the average labor cost for a rig crew per day ($200,000) and by the number of affected wells to obtain an estimated average annual labor cost to industry of $600,000 ($200,000 × 3) for this requirement. Summing the equipment and labor costs yields a total average annual cost to industry of $795,000 for this requirement. We divided the average annual equipment and labor cost by the number of entities (130) to obtain an average annual equipment and labor cost per entity of $6,115 ($795,000 ÷ 130).

[24] We assumed that the quarterly equipment and service costs of testing for capping stacks would be $5,000 per test. Additionally, we assumed that 4 capping stacks would be tested quarterly (or a total of 16 annual tests performed). We multiplied the costs per test by the number of annual tests in order to determine a total annual equipment and service cost to industry of $80,000 (16 × $5,000). We divided the annual equipment and service cost to industry by the number of entities (130) to obtain an average annual equipment and service cost per entity of $615 ($80,000 ÷ 130).

[25] We assumed that industry staff (a mid-level engineer) would spend 0.25 hours to include the additional information in the APM for a well. We assumed that APMs would be submitted for an average of 260 wells with installed packers per year. We multiplied the number of industry staff hours per well by the average hourly compensation rate for a mid-level industry engineer ($88.38) and by the estimated number of wells with installed packers for which an APM would be submitted per year to estimate an average annual labor cost to industry of $5,745 (0.25 × $88.38 × 260). We divided the average annual labor cost by the number of entities (130) to obtain an average annual labor cost per entity of $44 ($5,745 ÷ 130).

[26] We assumed that industry staff (a mid-level engineer) would spend 0.25 hours to include the additional information in the APM for a well. We also assumed that APMs would be submitted for an average of 1,010 wells with pulled and reinstalled packers per year. We multiplied the number of industry staff hours per well by the average hourly compensation rate for a mid-level industry engineer ($88.38) and the estimated number of wells with pulled and reinstalled packers for which an APM would be submitted per year to obtain an average annual labor cost to industry of $22,316 (0.25 × $88.38 × 1,010). We divided the average annual labor cost by the number of entities (130) to obtain an average annual labor cost per entity of $172 ($22,316 ÷ 130).

[27] We assumed that industry staff (administrative) would spend five minutes (0.08 hours) to submit a movement report and that industry would submit an average of 1,000 movement reports per year. We multiplied the number of industry staff hours per report by the average hourly compensation rate for an administrative staff ($29.82) and the average number of reports per year to obtain an average annual labor cost to industry of $2,485 (0.0833 × $29.82 × 1,000). We divided the average annual labor cost by the number of entities (130) to obtain an average annual labor cost per entity of $19 ($2,485 ÷ 130).

in an average annual labor cost to industry of $340 per entity.[28]

(i) Foundation requirements for MODUs and lift boats.

Proposed § 250.713(b) would introduce a requirement for foundation requirements for workovers, completions, and decommissioning. Operators must provide information to show that site-specific soil and oceanographic conditions would be capable of supporting the proposed rig unit. If operators provide sufficient site-specific information in the Exploration Plan (EP), Development and Production Plan (DPP), or Development Operations Coordination Document (DOCD) submitted to BOEM, operators may reference that information. 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 would be capable of supporting the rig unit or equipment installed on a subsea wellhead. For moored rigs, operators must submit a plan of the rigs anchor pattern approved in the EP, DPP, or DOCD in the APD or APM. This requirement would result in an average annual labor cost to industry of $340 per entity.[29]

(j) Real-time monitoring of well operations.

Proposed § 250.724 is a new section that lists requirements for:

—Monitoring well operations on rigs that have a subsea BOP, surface BOP on a floating facility, and rigs operating in HPHT reservoirs; and

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

In order to comply with this section, the OCS industry would incur annual equipment and labor costs associated with gathering, transmitting, and storing data. The costs associated with these new data collection and storage requirements would include an average annual equipment and labor cost of $311,538 per entity. The BSEE requests feedback related to the costs of compliance with monitoring of well operations with a subsea BOP.[30]

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

Proposed § 250.730 would list general requirements for BOP systems and system components and additions to the section would describe new documentation and verification requirements. Proposed § 250.731(c) would require verification by a BSEE-approved verification organization of specified aspects of equipment design, equipment tests, shear tests, and pressure integrity tests; and all certification documentation must be made available to BSEE. Proposed § 250.732(c) would require a comprehensive review by a BSEE-approved verification organization of BOP and related equipment being proposed for use in HPHT service. Proposed § 250.730(d) would require that quality management systems for BOP stacks be certified by an entity that meets the requirements of ISO 17011.

Additionally, operators may submit a request for approval of equipment manufactured under quality assurance programs other than API Spec. Q1. The BSEE may approve such a request, provided the operator submits relevant information about the alternative program. Costs associated with these new documentation and certification requirements would include an average annual equipment and labor cost of $13,706 per entity. The BSEE requests feedback related to the costs of compliance with these documentation and certification requirements for BOP systems and system components.[31]

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

Proposed § 250.731 would list the descriptions of BOP systems and system components that must be included in the applicable APD, APM, or other submittal for a well. Paragraph (a) would require the submittal to include descriptions of the rated capacities for the fluid-gas separator system, control fluid volumes, control system pressure to achieve a seal of each ram BOP, number of accumulator bottles and bottle banks, and control fluid volume calculations for the accumulator system. Paragraph (b) would add schematic drawing requirements, including labeling for the control system alarms and set points, control stations, and riser cross section. New paragraph (e) would require a listing of the functions with sequences and timing of autoshear, deadman, and EDS for subsea BOPs. For subsea BOPs, surface BOPs on a floating facility, and BOPs operating under HPHT conditions, new paragraph (f) would require submission of a certification that a Mechanical Integrity Assessment Report has been submitted within the past 12 months. New paragraph (c) would include a change in required certifications. The paragraph would require submission of certifications from a BSEE approved verification organization (rather than a ''qualified third-party'') that:

—Test data would demonstrate that the shear ram(s) would shear the drill

[28] We assumed that industry staff (a mid-level engineer) would spend 0.5 hours per APM to provide the additional information and that an average of 1,000 APMs would be affected per year. We multiplied the number of industry staff hours per APM by the average hourly compensation rate for a mid-level industry engineer ($88.38) and by the estimated number of APMs affected per year to obtain an average annual labor cost to industry of $44,190 (0.5 × $88.38 × 1,000). We divided the average annual labor cost by the number of entities (130) to obtain an average annual labor cost per entity of $340 ($44,190 ÷ 130).

[29] We assumed that industry staff (a mid-level engineer) would spend 0.5 hours per APM to provide the additional information and that an average of 1,000 APMs would be affected per year. We multiplied the number of industry staff hours per APM by the average hourly compensation rate for a mid-level industry engineer ($88.38) and by the estimated number of APMs affected per year to obtain an average annual labor cost to industry of $44,190 (0.5 × $88.38 × 1,000). We divided the average annual labor cost by the number of entities (130) to obtain an average annual labor cost per entity of $340 ($44,190 ÷ 130).

[30] We assumed that the average costs per day and the average operational days per year would be the same for rigs with subsea BOPs and rigs operating in HPHT reservoirs. Additionally, we assumed that a rig operates for 270 days per year (three operations per year and three months per operation) and that the average cost per day to perform continuous monitoring would be $5,000, including equipment and labor. We estimated that half of the rigs with subsea BOPs already conduct this monitoring. Thus, only half of rigs with subsea BOPs (20 rigs) would incur a new cost to comply with these requirements. Similarly, we assumed that 10 of the rigs operating in HPHT reservoirs would incur a new cost to comply with these requirements. We multiplied the time that the rig is operational per year by the average cost per day to perform monitoring and by the number of affected rigs to obtain an average annual equipment and labor cost to industry of $40.5 million (270 × $5,000 × 30). We divided the average annual equipment and labor cost by the number of entities (130) to obtain an average an average annual equipment and labor cost per entity of $311,538 ($40,500,000 ÷ 130).

[31] For proposed § 250.731(c), we assumed that the one-time equipment and service costs to industry would be $40,000. We estimated that 320 wells would incur a new cost to comply with these requirements. We multiplied the one-time cost of equipment and service by the number of affected wells to obtain the total one-time equipment and service cost to industry of $12,800,000 ($40,000 × 320), resulting in an average annual cost of $1,280,000 to industry. For § 250.732(c), we assumed that the annual costs would be $50,000, including equipment and service. We estimated that 10 wells would incur a new cost to comply with these requirements. We multiplied the annual cost of equipment and service by the number of affected wells to obtain an average annual equipment and service cost to industry of $500,000 ($50,000 × 10). For § 250.730(d), we assumed that a mid-level industry engineer would spend 2 hours to submit a request. We multiplied the compensation rate for a mid-level industry engineer ($88.38) by the number of hours to complete the submission and then multiplied this annual cost by the total number of wells (10) to determine the annual cost to industry of $1,768 (2 $88.38 × 10). The average annual cost to industry associated with these requirements is $1,781,768 ($1,280,000 + $500,000 + $1,768). We divided this average annual equipment and labor cost by the number of entities (130) to obtain average an average annual equipment and labor cost per entity of $13,706 ($1,781,768 ÷ 130).

pipe at the water depth (per proposed § 250.732(b)),
—The BOP would be designed, tested, and maintained to perform at the most extreme anticipated conditions; and
—The accumulator systems would have sufficient fluid to function the BOP system without assistance from the charging system.

These proposed requirements would be 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* investigation reports. These requirements would be necessary to help BSEE verify that the accumulator system would have sufficient fluid to function the BOP system without assistance from the charging system. The proposed requirements to provide additional documentation about the BOP system and system components in the APD, APM, or other submittal would result in an average annual labor cost to industry of $218 per entity.[32] The BSEE was unable to locate any applicable data or comparative cost estimates, and therefore was unable to determine a definitive cost estimate for the annual costs to industry associated with the change in the required independent third-party verifications referenced in new paragraph (a). The BSEE requests feedback from the public and industry on costs associated with the change in the verification requirements.

(m) Submission of a Mechanical Integrity Assessment Report by a BSEE-approved verification organization.

Proposed § 250.732(d) would include new requirements on the submission of a Mechanical Integrity Assessment Report on the BOP stack and systems. New paragraph (d) would outline the requirements for this report, which must be completed by a BSEE-approved verification organization and submitted by the operator for operations that would require the use of a subsea BOP, a surface BOP on a floating facility, or a BOP that is being used in HPHT operations. Proposed new § 250.731(f) would require certification in the applicable permit stating that this report has been submitted within the past 12 months. The third-party reporting would enhance the BSEE review and permitting process and would ensure that BSEE is aware of repairs or other changes to the operating BOPs. These reporting requirements would result in new costs to industry consisting of capital and labor costs for creating reports and submitting them to BSEE. The analysis estimated an average annual cost to industry of $37,032 per entity.[33]

(n) New surface BOP requirements.

Proposed § 250.733 would include new requirements for surface BOP stacks. New paragraph (e) would require that hydraulically operated locks are installed with surface BOPs. The BSEE was unable to locate any applicable data or comparative cost estimates and therefore was unable to determine a definitive cost estimate for the labor and equipment costs to industry associated with the installation of hydraulically operated locks. The BSEE requests feedback related to the costs of compliance with this new surface BOP stack requirement.

(o) New subsea BOP system requirements.

Proposed § 250.734 would include new requirements for subsea BOP systems, based on recommendations from the *Deepwater Horizon* investigations. Paragraph (a) would require that BOPs be equipped with two shear rams and would outline the requirements for the shear rams. These additions would assist in emergency well-control planning. The BSEE recognizes that the equipment and labor costs associated with these new subsea BOP system requirements would be case-specific. For example, the costs would depend on the age of the rig and BOP system, the BOP system type, and the size of the rig, among other factors.

The costs associated with the shear ram requirements in paragraph (a) would include an average one-time compliance cost to industry of $384,615 per entity.[34] The BSEE welcomes feedback related to the costs of compliance with these new technology requirements.

(p) New surface accumulator system requirements.

Proposed § 250.735(a) would list new requirements for the surface accumulator system of a BOP. The surface accumulator system must operate all BOP functions against MASP with 200 psi above pre-charge without use of the charging system. This revision would ensure that the BOP system would be capable of operating all critical functions. The requirement that the surface accumulator system would operate all functions for all BOP systems would result in a one-time equipment and labor cost to industry of $21,713 per entity.[35]

(q) Chart recorders.

Proposed § 250.737(c) would address BOP testing and introduce a requirement that each test must hold the required pressure for five minutes while using a four-hour chart. This would allow the chart to detect a leak during the test. This testing requirement would result in a one-time equipment and labor cost to industry of $1,388 per entity.[36]

---

[32] We assumed that industry staff (a mid-level engineer) would spend one hour to include additional information in the APD, APM, or other submittal for a well. We multiplied the number of industry staff hours per well by the average hourly compensation rate for a mid-level industry engineer ($88.38) and by the average number of wells drilled per year (320) to obtain an average annual labor cost to industry of $28,282 (1 × $88.38 × 320). We divided the average annual labor cost by the number of entities (130) to obtain an average annual labor cost per entity of $218 ($28,282 ÷ 130).

[33] For capital costs, we assumed an annual cost of $15,000 for each well which results in an annual capital cost of $4.8 million ($15,000 × 320). For labor costs, we assumed that industry staff (a mid-level engineer) would spend a half hour to prepare a report for each well. We multiplied the number of industry staff hours per well by the average hourly compensation rate for a mid-level industry engineer ($88.38) and by the average number of wells drilled per year (320) to obtain an average annual labor cost to industry of $14,141 (0.5 × $88.38 × 320). The average annual labor and capital cost to industry. associated with these requirements is $4,814,141 ($4,800,000 + $14,141). We divided the average annual labor and capital cost to industry by the number of entities (130) to obtain an average annual labor and capital cost per entity of $37,032 ($4,814,141 ÷ 130).

[34] API Standard 53 includes the requirements under new paragraph (a) for all rigs with the exception of moored rigs. We estimated that 5 moored rigs would be affected and that the one-time capital compliance cost associated with these shear ram requirements would be $10,000,000 per rig. To calculate the total one-time capital costs to industry, we multiplied the equipment cost per rig by the number of affected rigs to yield a total cost to industry of $50,000,000 ($10,000,000 × 5). We divided the average one-time equipment and labor cost by the number of entities (130) to obtain an average one-time cost per entity of $384,615 ($50,000,000 ÷ 130).

[35] We assumed that the average cost of the additional equipment needed to meet the requirements would be $25,000 per rig. It is unknown how many rigs already comply; thus, we made a conservative assumption that all rigs would be affected (90 rigs). We multiplied the equipment cost per rig by the number of affected rigs to obtain an estimated one-time equipment cost of $2.25 million ($25,000 × 90). For the one-time labor cost to industry, it was estimated that one to three days of industry time would be required per rig to install the new equipment. To be conservative, we assumed that industry staff (a mid-level engineer) would spend 72 hours to install the new equipment on a rig. We multiplied the number of industry staff hours per rig by the average hourly compensation rate for a mid-level industry engineer ($88.38) and by the number of affected rigs to obtain an estimated one-time labor cost to industry of $572,702 (72 × $88.38 × 90). Summing the equipment and labor costs resulted in a total one-time cost to industry of $2,822,708. We divided the one-time equipment and labor cost by the number of entities (130) to obtain a one-time equipment and labor cost per entity of $21,713 ($2,822,708 ÷ 130).

[36] We assumed that each rig would require a chart recorder for an average cost of $2,000 per rig. We multiplied the average equipment cost per rig by the total number of rigs (90) to obtain an estimated one-time equipment cost to industry of $180,000 ($2,000 × 90). We assumed that industry staff (rig crew) would spend five minutes (0.08 hours) per rig

Continued

(r) Notification and procedure requirements for testing of surface BOP systems.

Proposed § 250.737(d)(2) would expand notification and procedure requirements regarding the use of water to test a surface BOP system. This notification and procedure requirement would result in an average annual labor cost to industry of $41 per entity.[37]

(s) Alternating BOP control station function testing.

Proposed § 250.737(d)(5) would expand the requirements for function testing BOP control stations. It would require that the operator designate the BOP control stations as primary and secondary and alternate function testing of each station weekly. This testing requirement would result in an average operations cost to industry of $192,308 per entity.[38] The BSEE requests feedback related to the costs of compliance with alternating BOP control station function testing.

(t) ROV intervention function testing.

Proposed § 250.737(d)(12) would include requirements for testing ROV intervention functions to include testing and verifying the closure of all ROV intervention functions on a subsea BOP. The operator would have to test and verify closure of the selected ram. This testing requirement would result in an average annual operations cost to industry of $3,205 per entity.[39]

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

Proposed § 250.737(d)(13) would expand the requirements for function testing of autoshear, deadman, and EDSs on subsea BOPs. It would require that the test procedures submitted for BSEE District Manager approval include a schematic of the circuitry of the system, the approved schematics of the BOP control system, and a description of how the ROV would be used during the operation. It would also outline 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 (per proposed § 250.737(d)(13)). It would require that the blind-shear rams be tested to verify closure. The operator must document the plan to verify closure of the casing shear ram, if installed, as well as all test results. These documentation and testing requirements would result in an average one-time equipment cost to industry of $769 per entity and an average annual operations cost of $38,462 per entity.[40]

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

Proposed § 250.738 would describe the required actions for specified situations involving BOP equipment or systems. Paragraphs (b), (i), and (o) would include requirements for reports from verification organizations. Reports previously required to be prepared by a ''qualified third-party'' under these sections would be required to be prepared by a ''BSEE-approved verification organization.'' Proposed § 250.738(m) would include a similar change and introduce a requirement that an operator request approval from the BSEE District Manager to use well-control equipment not covered in Subpart G. The operator must submit a report from a BSEE-approved verification organization, as well as any other information required by the District Manager. This approval request requirement would result in an average annual labor cost to industry of approximately $1 per entity.[41] The BSEE was unable to locate any applicable data or comparative cost estimates and therefore was unable to determine a definitive cost estimate for the annual costs to industry associated with the third-party verification. The BSEE welcomes feedback from the public or industry on costs associated with the third-party verification requirements.

(w) Breakdown and inspection of the BOP system and components.

Proposed § 250.739(b) would introduce a requirement for a complete breakdown and inspection of the BOP and every associated component every 5 years. During this complete breakdown and inspection, a BSEE-approved verification organization must document the inspection and any problems encountered. This BSEE-approved verification organization's report must be available to BSEE upon request. This additional requirement would be necessary to ensure that the components on the BOP stack are 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 would result in an average cost to industry to obtain third-party reports of $165,385 per entity during the year of inspection, which would occur

to install the equipment. We multiplied the number of industry staff hours per rig by the average hourly compensation rate for a rig crew staff ($56.80) and by the total number of rigs to obtain an estimated one-time labor cost to industry of $426 (0.0833 × $56.80 × 90). Summing the equipment and labor costs resulted in a total one-time cost to industry of $180,426. We divided the one-time equipment and labor cost by the number of entities (130) to obtain a one-time equipment and labor cost per entity of $1,388 ($180,426 ÷ 130).

[37] We assumed that a mid-level industry engineer would spend 1 additional hour on a submittal as a result of these expanded requirements. We multiplied the compensation rate for a mid-level industry engineer ($88.38) by the number of hours to complete the submission and then multiplied this annual cost by the total number of submittals (60) to determine the annual cost to industry of $5,303 (1 × $88.38 × 60). We divided the average annual labor cost by the number of entities (130) to obtain an average annual labor cost per entity of $41 ($5,303 ÷ 130).

[38] We assumed that testing would require 0.5 days per rig per year (two hours every two weeks for three months). Because subsea and surface BOPs rigs have different daily rig operating costs, we performed separate calculations for the costs for subsea and surface BOP rigs. For subsea BOP rigs, we multiplied the time required to conduct the testing per rig by the average daily rig operating cost for subsea BOP rigs ($1 million) and by the number of subsea BOP rigs (40) for an average annual cost of $20 million for subsea BOP rigs (0.5 × $1 million × 40). For surface BOP rigs, we multiplied the time required to conduct the testing per rig by the average daily rig operating cost for surface BOP rigs ($200,000) and by the number of surface BOP rigs (50) for an average annual cost of $5 million for surface BOP rigs (0.5 × $200,000 × 50). Summing the average annual costs for subsea BOP rigs and surface BOP rigs resulted in an average annual operations cost to industry associated with this provision of $25 million. We divided the average annual operations cost to industry by the number of entities (130) to obtain an average annual operations cost per entity of $192,308 ($25,000,000 ÷ 130).

[39] We assumed that it would take five minutes per well to conduct the testing and that 120 wells would be affected (40 subsea BOP rigs with three wells per rig). We multiplied the time diverted for testing in a day 0.003472 (5 min ÷ 60 min ÷ 24 hours) by the daily operating cost per rig ($1,000,000) and by the estimated number of wells affected per year to obtain an average annual operations cost to industry of $416,667 (0.03 × 120 × $1,000,000). We divided the average annual operations cost by the number of entities (130) to obtain an average annual operations cost per entity of $3,205 ($416,667 ÷ 130).

[40] We assumed that the average cost of the sensing device would be $2,500 per rig. We multiplied the equipment cost by the total number of subsea BOP rigs (40) to obtain the one-time equipment cost to industry of $100,000 ($2,500 × 40). We divided the equipment cost by the number of entities (130) to obtain a one-time equipment cost per entity of $769 ($100,000 ÷ 130). We assumed that it would take one hour per well to perform the testing and documentation tasks required by this provision, and that each subsea BOP rig would be affected (40 subsea rigs). We multiplied the time diverted for testing in a day 0.125 (1 hour ÷ 24 hours) by the daily operating cost per rig ($1,000,000) and by the estimated number of rigs affected per year to obtain an average annual operations cost to industry of $5 million (0.125 × 40 × $1,000,000). We divided the average annual operations cost by the number of entities (130) to obtain an average annual operations cost per entity of $38,462 ($5,000,000 ÷ 130).

[41] We assumed that industry staff (a mid-level engineer) would spend 0.5 hours to submit an equipment approval request and report. We also assumed that industry would submit a request and report for an average of two deepwater rigs per year. We multiplied the number of industry staff hours per submission by the average hourly compensation rate for a mid-level industry engineer ($88.38) and the average number of submissions per year to obtain an average annual labor cost to industry of $88 (0.5 × $88.38 × 2). We divided the average annual labor cost by the number of entities (130) to obtain an average annual labor cost per entity of $1 ($88 ÷ 130).

once every 5 years or twice during the 10-year analysis period.[42] We assumed that costs would be incurred in year 1 and year 6 of the 10-year analysis period.

(x) Additional recordkeeping for real-time monitoring.

Proposed §§ 250.740(a) and § 250.741(b) would introduce requirements for additional recordkeeping of real-time monitoring data for well operations. These additional records would require an average additional annual labor cost to industry of $14 per entity.[43]

(y) Industry familiarization with new regulations.

When the new regulation takes effect, operators would need to read and interpret the rule. Through this review, operators would familiarize themselves with the structure of the new rule and identify any new provisions relevant to their operations. Operators would evaluate whether any new action must be taken to achieve compliance with the rule. Reviewing the new regulations would require staff time, representing an average one-time labor cost on industry of $216 per entity.[44]

(z) Total Cost Burden for Small Entities.

The BSEE's calculations indicate that the total cost burden of this proposed rule would be $6,783,880 per affected small entity over 10 years, which yields an average annual cost of $678,388, as presented in Exhibit 4. Four provisions comprise approximately 85 percent of the cost to small entities:

—Monitoring of well operations with a subsea BOP;
—Alternating BOP control station function testing;
—Autoshear, deadman, and EDS system function testing on subsea BOPs; and
—New subsea BOP system requirements.

Exhibit 5 displays estimates of costs to small entities as a percentage of revenues.[45] In 8 of the 10 years in the analysis period, the proposed rule represents a cost of $595,628 per entity. In the first year, costs would be higher at $1,268,175 per entity as a result of the one-time equipment and inspection costs. In year 6, small entities would incur the costs from BOP major inspections, which would be performed every 5 years.

The costs of the rule as a proportion of small entity revenue range from 1.30 percent in most years to 2.78 percent in the first year. The BSEE considers that a rule has a ''significant economic impact'' when the total annual cost associated with the rule is equal to or exceeds 1 percent of annual revenue. Thus, the rule is expected to have a significant economic impact on the average participating small operators, lease holders, and pipeline right-of-way holders. Thus, BSEE concluded that this proposed rule will have a significant economic impact on a substantial number of small entities.

EXHIBIT 4—PER ENTITY COST OF THE PROPOSED RULE BY PROVISION [1]

	Total 10 year cost per entity (undiscounted)	Average annual cost per entity (undiscounted)	Percent of total cost
(a) Additional information in the description of well drilling design criteria	$2,176	$218	0.03
(b) Additional information in the drilling prognosis	544	$54	0.01
(c) Prohibition of a liner as conductor casing	61,154	6,115	0.90
(d) Additional capping stack testing requirements	6,154	615	0.09
(e) Additional information in the APM for installed packers	442	44	0.01
(f) Additional information in the APM for pulled and reinstalled packers	1,717	172	0.03
(g) Rig movement reporting	191	19	0.00
(h) and (i) Information on MODUs, including lift boats	6,799	680	0.10
(j) Real-time monitoring of well operations	3,115,385	311,538	45.92
(k) Additional documentation and certification requirements for BOP systems and system components	137,059	13,706	2.02
(l) Additional information in the APD, APM, or other submittal for BOP systems and system components	2,176	218	0.03
(m) Submission of a Mechanical Integrity Assessment Report by a BSEE-approved verification organization	370,319	37,032	5.46
(n) New surface BOP requirements	Data not available; requesting comments		
(o) New subsea BOP system requirements [2]	384,615	38,462	5.67
(p) New surface accumulator system requirements	21,713	2,171	0.32
(q) Chart recorders	1,388	139	0.02
(r) Use water to test surface BOP system	408	41	0.01

[42] For subsea BOP rigs, we assumed that equipment and labor cost would be $350,000 per rig. We multiplied the total number of subsea BOP rigs (40) by the equipment and labor cost to obtain an inspection-year cost of $14 million ($350,000 × 40), which occurs every 5 years for subsea BOP rigs. For surface BOP rigs, we assumed that equipment and labor cost would be $150,000 per rig. We multiplied the total number of surface BOP rigs (50) by the equipment and labor cost to obtain an inspection-year cost of $7.5 million ($150,000 × 50), which occurs every 5 years for surface BOP rigs. The sum of subsea and surface BOP costs are $21.5 million during the year of inspection. We divided this total cost by the number of entities (130) to obtain an average cost of inspection per entity of $165,385 ($21,500,000 ÷ 130).

[43] We assumed that industry staff (administrative staff) would spend 0.5 hours to submit a report. We multiplied the number of industry staff hours per submission by the average hourly compensation rate for administrative staff ($29.82) and then multiplied this annual cost by the number of affected wells (120, based on the assumption of three wells per subsea BOP rig) to obtain an average annual labor cost to industry of $1,789 (0.5 × $29.82 × 120). We divided the average annual labor cost to industry by the number of entities (130) to obtain an average annual labor cost per entity of $14 ($1,789 ÷ 130).

[44] We assumed that industry staff (a professional engineer, supervisory) would spend two hours to review the new regulation. The average hourly wage rate for a professional engineer (supervisory) is $76.00, based on BSEE's Supporting Statement A (BSEE Production Safety Systems). We multiplied this wage rate by the private sector loaded wage factor of 1.42 to account for employee benefits, resulting in a loaded average hourly compensation rate of $107.92. We assumed that an industry staff would review the new regulation at each of the 130 field offices. We multiplied the number of hours per review by the average hourly compensation rate and by the number of field offices, resulting in an estimated one-time labor cost to industry of $28,059 (2 × $107.92 × 130). We divided the one-time labor cost by the number of entities (130) to obtain an average one-time labor cost of $216 ($28,059 ÷ 130).

[45] The source for the estimated small business revenue is the RIA for the BSEE Final Rulemaking ''Increased Safety Measures for Energy Development on the Outer Continental Shelf'' (77 FR 50856; August 22, 2012). The data in the source document is from the Office of Natural Resources Revenue. The RIA can be viewed here: *http://www.regulations.gov/#!documentDetail;D=BSEE-2012-0002-0047.* The data source reports the total 2009 small company revenue to be $4,113,000,000. We calculated the average revenue per small business by dividing the total small business revenue by the number of small businesses subject to the rule ($4,113,000,000/90 operators) to obtain an average of $45,700,000 per operator.

EXHIBIT 4—PER ENTITY COST OF THE PROPOSED RULE BY PROVISION [1]—Continued

	Total 10 year cost per entity (undiscounted)	Average annual cost per entity (undiscounted)	Percent of total cost
(s)Alternating BOP control station function testing	1,923,077	192,308	28.35
(t) ROV intervention function testing	32,051	3,205	0.47
(u) Autoshear, deadman, and EDS system function testing on subsea BOPs	385,385	38,538	5.68
(v) Approval for well-control equipment not covered in Subpart G	7	1	0.00
(w) Breakdown and inspection of BOP system and components	330,769	33,077	4.88
(x) Record-keeping for real-time monitoring	138	14	0.00
(y) Industry familiarization with the new rule	216	22	0.00
Total	6,783,880	678,388	100.00

[1] Totals may not add because of rounding.
[2] This is a lower-bound estimate of the costs of this provision; BSEE seeks comment on costs that we were unable to estimate (see section 4 above for details).

EXHIBIT 5—ANNUAL COST AND REVENUE PER ENTITY

Year	2015	2016–2019 (each year the same)	2020	2021–2024 (each year the same)
Annual Industry Cost Stream for Proposed Rule a	$164,728,509	$77,297,317	$98,797,317	$77,297,317
Total Entities b	130	130	130	130
Average Annual Cost per Entity c = a ÷ b	1,268,175	595,628	761,012	595,628
Average Annual Revenue for Small Entities [1] d	45,700,000	45,700,000	45,700,000	45,700,000
Cost from Proposed Rule as a Percentage of Annual Revenue e = c ÷ d	2.78%	1.30%	1.67%	1.30%

[1] The source for this estimate is the RIA for the BSEE Final Rulemaking "Increased Safety Measures for Energy Development on the Outer Continental Shelf" (77 CFR 50856; August 22, 2012). The data in the source document is from the Office of Natural Resource Revenue. The RIA can be viewed here: *http://www.regulations.gov/#!documentDetail;D=BSEE-2012-0002-0047.* The data source reports the total 2009 small company revenue to be $4,113,000,000. We calculated the average revenue per small business by dividing the total small business revenue by the number of small businesses subject to the rule ($4,113,000,000/90) to obtain an average of $45,700,000 per operator.

4. Identification of All Relevant Federal Rules That May Duplicate, Overlap, or Conflict With the Proposed Rule

The proposed rule does not conflict with any relevant federal rules or duplicate or overlap with any Federal rules in any way that would unnecessarily add cumulative regulatory burdens on small entities without any gain in regulatory benefits. However, BSEE requests comments identifying any federal rules that may duplicate, overlap, or conflict with the proposed rule.

5. Description of Significant Alternatives to the Proposed Rule

BSEE has considered three alternatives:

BSEE has considered three regulatory alternatives:

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

BOP PRESSURE TESTING

Operation	Current testing frequency	Proposed testing frequency
Drilling/Completions	14 days	14 days
Workover/Decommissioning	7 days	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 (*e.g.,* 7 or 14 days depending upon the type of operation) to 21 days for all operations. The following chart identifies the BOP testing changes related to Alternative 2; or

BOP PRESSURE TESTING

Operation	Current testing frequency	Proposed testing frequency (Alternative 1)	Alternative 2 testing frequency
Drilling/Completions	14 days	14 days	21 days
Workover/Decommissioning	7 days	14 days	21 days*

* includes change from current 7 days to proposed 14 days

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

Alternative 2 results in a time-savings benefit to industry but no additional costs to industry, and thus the costs are the same for Alternatives 1 and 2. By taking no regulatory action in 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.[46]

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

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

The operating risk for small companies to incur safety or environmental accidents is not necessarily lower than it is for larger companies. Offshore operations are highly technical and can be hazardous. Adverse consequences in the event of incidents are similar regardless of the operator's size. The proposed rule would reduce risk for entities of all sizes. Nonetheless, BSEE is requesting comment on the time it would take to comply with the proposed rule and the costs of these proposed policies on small entities, with the goal of ensuring thorough consideration and discussion at the final rule stage. The BSEE specifically requests comments on the burden estimates discussed above as well as information on regulatory alternatives that would reduce the burden on small entities (*e.g.,* different compliance requirements for small entities, alternative testing requirements and periods, and exemption from regulatory requirements).

[46] *See* sources listed in n. 6.

Small Business Regulatory Enforcement Fairness Act

The proposed rule is a major rule under the Small Business Regulatory Enforcement Fairness Act, 5 U.S.C. 801 *et seq.* This proposed rule:

(1) Would have an annual effect on the economy of $100 million or more.

(2) Would cause a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions.

(3) Would not have significant adverse effects on competition, employment, investment, productivity, innovation, or the ability of U.S.-based enterprises to compete with foreign-based enterprises.

The requirements would apply to all entities operating on the OCS regardless of company designation as a small business. For more information on costs affecting small businesses, see the RFA discussion.

Unfunded Mandates Reform Act of 1995

This proposed rule would not impose an unfunded mandate on State, local, or tribal governments or the private sector of more than $100 million per year. The proposed rule would not have a significant or unique effect on State, local, or tribal governments or the private sector. A statement containing the information required by the Unfunded Mandates Reform Act, 2 U.S.C. 1501 *et seq.,* is not required.

Takings Implication Assessment (E.O. 12630)

Under the criteria in E.O. 12630, this proposed rule does not have significant takings implications. The proposed rule is not a governmental action capable of interference with constitutionally protected property rights. A Takings Implication Assessment is not required.

Federalism (E.O. 13132)

Under the criteria in E.O. 13132, this proposed rule does not have federalism implications. This proposed rule would not substantially and directly affect the relationship between the Federal and State governments. To the extent that State and local governments have a role in OCS activities, this proposed rule would not affect that role. A federalism assessment is not required.

Civil Justice Reform (E.O. 12988)

This rule complies with the requirements of E.O. 12988. Specifically, this rule:

(1) Meets the criteria of section 3(a) requiring that all regulations be reviewed to eliminate errors and ambiguity and be written to minimize litigation; and

(2) Meets the criteria of section 3(b)(2) requiring that all regulations be written in clear language and contain clear legal standards.

Consultation With Indian Tribes (E.O. 13175)

Under the criteria in E.O. 13175, we have evaluated this proposed rule and determined that it has no substantial direct effects on federally recognized Indian tribes. The BSEE is committed to regular and meaningful consultation and collaboration with tribes on policy decisions that have tribal implications. The BSEE will consult with any tribe that requests consultation about this proposed rule.

Paperwork Reduction Act (PRA) of 1995

This proposed rule contains collections of information that will be submitted to OMB for review and approval under the PRA, 44 U.S.C. 3501 *et seq.* As part of its continuing effort to reduce paperwork and burdens on respondents, BSEE invites the public and other Federal agencies to comment on any aspect of the reporting and recordkeeping burden. If you wish to comment on the information collection (IC) aspects of this proposed rule, you may send your comments directly to OMB and send a copy of your comments to the Regulations and Standards Branch (see the **ADDRESSES** section of this proposed rule). Please reference 30 CFR part 250, subpart G, Blowout Preventer Systems and Well Control, 1014–NEW, in your comments. To see a copy of the information collection request submitted to OMB, go to *http://www.reginfo.gov* (select Information Collection Review, Currently Under Review); or you may obtain a copy of the supporting statement for the new collection of information by contacting the Bureau's Information Collection Clearance Officer at (703) 787–1607.

The PRA provides that an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB is required to make a decision concerning the collection of information contained in these proposed regulations 30–60 days after publication of this document in the **Federal Register**. Therefore, a comment to OMB is best assured of being fully considered if OMB receives it by May 18, 2015. This does not affect the deadline for the public to comment to BSEE on the proposed regulations.

The title of the collection of information for this rule is 30 CFR 250, Subpart G, Blowout Preventer Systems and Well Control (Proposed Rulemaking). The proposed regulations concern BOP system requirements, maintaining well control among others, and the information is used in BSEE's efforts to regulate oil and gas operations on the OCS to protect life and the environment, conserve natural resources, and prevent waste.

Potential respondents comprise Federal OCS oil, gas, and sulphur operators and lessees. Responses to this collection of information are mandatory, or are required to obtain or retain a benefit; they are also submitted on occasion, daily and weekly (during drilling operations), monthly, quarterly, biennially, and as a result of situations encountered depending upon the requirement. The IC does not include questions of a sensitive nature. The BSEE will protect proprietary information according to the Freedom of Information Act (5 U.S.C. 552) and DOI implementing regulations (43 CFR 2), 30 CFR part 252, *OCS Oil and Gas Information Program,* and 30 CFR 250.197, *Data and information to be made available to the public or for limited inspection.*

This proposed rule affects Subpart A (1014–0022, expiration 8/31/2017); Subpart B (1014–0024, expiration 12/31/2015); Applications for Permits to Drill (1014–0025, expiration 4/30/17); Applications for Permits to Modify (1014–0026, expiration 5/31/17); Subpart D (1014–0018, expiration 10/31/17); Subpart E, (1014–0004, expiration 12/31/16); Subpart F, (1014–0001, expiration 12/31/16); Subpart P, (1014–0006, expiration 12/31/16); and Subpart Q, (1014–0010, expiration 10/31/16).

This rule would also codify NTL 2013–G01, Global Positioning Systems (GPS) for Mobile Offshore Drilling Units (MODUs) (1014–0013, expiration 1/31/2016).

This rule proposes to create new 30 CFR part 250, subpart G, Well Operations and Equipment, which will combine common requirements from the various other subparts mentioned, as well as add new requirements. The following explanations apply to this section: in the burden table, the OMB currently approved hour and/non-hour cost burdens for requirements will be identified with an asterisk (*); *italics* show *revision(s)* of existing requirements; and brackets indicate new requirements.

A vast majority of this proposed rule contains IC burdens OMB has already approved (174,686 burden hours* and $102,500 non-hour cost burdens*). We are revising some existing requirements (+ *5,052 burden hours);* and adding [new] regulatory requirements (+ [11,701 burden hours]) for a total of 191,439 burden hours.

The following is a brief explanation of how the proposed regulatory changes affect the various subpart and form burdens:

- Subpart A—transferred the currently approved burden hours from Subpart D for BOPs pertaining to alternative procedures and departures (12,300 hours*).
- Subpart B—*revised* the requirement by adding information to be submitted with DWOPs pertaining to free standing hybrid risers (FSHR) (9,000 hours*; + *48 hours*).
- APD—added NEW burden hours pertaining to requirements including, but not limited to, ECD information, current monitoring, changes to casing, *etc.* (47,800 hours* + [1,122 hours]). Because the responses remained unchanged, we did not list the non-hour costs burdens associated with APDs since the dollar amount will not change.
- APM—added NEW burden hours pertaining to requirements including, but not limited to, descriptions/calculations of production packer setting depth, annulus monitoring plan information, *etc.* (11,321 hours* + [1,929 hours]). Because the responses remained unchanged, we did not list the non-hour costs burdens associated with APMs since the dollar amount will not change.
- Subpart D—

(1) relocated common well operation and equipment requirements (10,811 hours*).

(2) revised requirements for additional information relating to safe drilling margins, well head descriptions, casing or line centralization during cementing, submitting any changes to approved plans, permits, or submittal (+ *4,859 hours*).

(3) added NEW burden hours pertaining to requirements relating to, but not limited to, cementing, source control and containment capabilities, etc., (+ [1,923 hours]).

- Subpart G—

(1) relocated burden hours from OMB currently approved requirements in D, E, F, P, and Q, that pertain to rig requirements, well operations, BOP system requirements, etc., as well as the hour and non-hour cost burden from GPS for MODUs (NTL 2013–G01) (83,454 hours* and $102,500 non-hour cost burden*).

(2) revised requirements that were relocated from other subparts in 30 CFR 250 for additional information that may be needed for properly functioning acoustic systems, EDS, rating pressure, etc., and requirements needing approval by the District Manager (+ [145 hours]).

(3) added NEW requirements pertaining to, but not limited to, warm or cold stacking for MODUs, dropped objects plan, real-time monitoring, pressure tests, etc., (+ [6,727 hours]).

- Subparts P and Q have only cross references to new Subpart G or current Subpart D and have no new associated burdens.

Once this rule becomes effective, BSEE will use the approved OMB control number for the Subpart G information collection. The affected remaining subparts discussed in this rule will have their information collection burdens adjusted accordingly through the renewal process.

BURDEN TABLE

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

30 CFR 250 Current *Revision* NEW	Reporting and recordkeeping requirement+ (BSEE-Approved Verification Organization = BAVO)	Hour burden	Average number of annual responses	Annual burden hours (rounded)
Subpart A				
[107]	NEW: 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

BURDEN TABLE—Continued

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

30 CFR 250 Current *Revision* NEW	Reporting and recordkeeping requirement+ (BSEE-Approved Verification Organization = BAVO)	Hour burden	Average number of annual responses	Annual burden hours (rounded)
141; 198; [701; 720(a)(2); 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.	20	496 requests	9,920 *
142; 198; 702	Request approval of departure from operating requirements not specifically covered elsewhere in regulatory requirements, along with supporting documentation if applicable.	2.5	952 requests	2,380 *
Subtotal (A)			1,448 responses	12,300 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*.	750 *4*	12 plans	9,000 * *48*
Subtotal (B)			12 responses	9,000 hours * *48 hours* 9,048 hours
		Applications for Permit to Drill (APD)		
410–418; [420(a)(7)]; 423(c)(1); [428(b), (k)]; plus various references in Subparts A, D, E, F, [G (701; 702; 713(a), (b), (e), (g); 720(b); 721(g)(4); 724(b); 731; 733(b);734(b), (c); 737(a)(3), (b)(2), (b)(3), (d)(2), (d)(3), (d)(4), (d)(12), (d)(13); 738(m), (n)]; H; and P.	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*;* [ECD information]*;* 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, height above water line etc.); location of ruptured disks; description of mudline level to displace cement; how the operator will visually monitor returns; PE certification showing approval of changes to casing setting depths; description of source control and containment capabilities; EDS; annulus monitoring plan information; any additional information required by District Manager]; etc.) and requests for various approvals required in Subpart D (including §§ *250.418(g);* 427, 428, 432, 460, 490(c)) and submitted via the form; upon request, make available to BSEE.	114.98 2.75	408 applications	46,912 * 1,122
[420(b)(4)]; 428; 465(a)(1); [721(g)(4); 731; 733(f); 734(b), (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 (on a case-by-case basis)].	1.34	662 submittals	888 *

BURDEN TABLE—Continued

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

30 CFR 250 Current *Revision* NEW	Reporting and recordkeeping requirement+ (BSEE-Approved Verification Organization = BAVO)	Hour burden	Average number of annual responses	Annual burden hours (rounded)
Subtotal (APD)	....	....	.... 1,070 responses	47,800 hours* [1,122 hours] 48,922 hours
Application for Permit to Modify (APM)				
460; 465; plus various ref in 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), (f), 734(b)(1); 737(d)(2), (d)(3), (d)(4), (d)(12), (d)(13); 738(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]; 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.	3.377 .... [40 min]	2,893 applications	9,770* [1,929]
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	11,321 hours* [1,929 hours] 13,250 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 .... *1*	239 submittals	478* *239*
421(b)	Alaska only: Discuss the cement fill level with the District Manager.	1	1 discussion	1*
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)]; plus various references in Subparts A, D, [G].	In the GOM OCS Region, submit drilling activity reports weekly (District Manager may require more frequent submittals on a case-by-case basis) 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)] plus various references in Subparts 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 × 365 days × 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 (if taken to ensure safety of crew/prevent well-control event); 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]

BURDEN TABLE—Continued

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

30 CFR 250 Current *Revision* NEW	Reporting and recordkeeping requirement+ (BSEE-Approved Verification Organization = BAVO)	Hour burden	Average number of annual responses	Annual burden hours (rounded)
[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 to the Regional Supervisor 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 at least 21 days prior to pressure testing; needs to be witnessed by BSEE and a BAVO.	[0.5]	[150 notifications]	[75]
Subtotal (D)			6,722 responses *1,014 responses* [985 responses] 8,721 responses	10,811 hours*. *4,859 hours* [1,923 hours] 17,593 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 procedures, [EDS], 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 to close diverter or BOP; total time for entire drill. The BSEE may require you to conduct a well-control drill during an inspection.	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 72 hours prior to movement; if the initial date changes by more than 24 hours, submit updated BSEE–0144*.	0.2	151 submittals	30 *

BURDEN TABLE—Continued

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

30 CFR 250 Current *Revision* NEW	Reporting and recordkeeping requirement+ (BSEE-Approved Verification Organization = BAVO)	Hour burden	Average number of annual responses	Annual burden hours (rounded)
[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]	[25 notifications]	[13]
[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 or lift boat 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 on a case-by-case basis if sufficient information is not available.	5	30 reports	150 *
[713(b)]	Reference to Exploration Plan, Development and Production Plan, and Development Operations Coordination Document (30 CFR 550, Subpart B).	Burden covered under 1010–0151		0
[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 or lift boat.	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 societ.	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	0.25	1 rig.	
	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.		1 notification	1 *
	2–Install and protect tracking/locator devices—(these are replacement GPS devices or new rigs).	20 devices per year for replacement and/or new × $325.00 = $6,500 *		
	3—Pay monthly tracking fee for GPS devices already placed on MODUs/rig..	40 rigs × $50/month = ($600/year per 1 rig) = $24,000 *		
	4—Rent GPS devices and pay monthly tracking fee per rig.	40 rigs @$1,800 per year = $72,000 *		
Subtotal (G—Rig Req.).			16,313 responses [105 responses] 16,418 responses	14,141 hours * [1,783 hours] 15,924 hours
			$102,500 Non-hour cost burdens *	

BURDEN TABLE—Continued

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

30 CFR 250 Current *Revision* NEW	Reporting and recordkeeping requirement+ (BSEE-Approved Verification Organization = BAVO)	Hour burden	Average number of annual responses	Annual burden hours (rounded)
	Well Operations			
[720(a)]	NEW: Notify and obtain approval from the District Manager when interrupting operations before getting off the well.	[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 step-by-step written procedures how to displace the fluids, shear pipe procedures, etc.	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 for proper seal, along with PE certification of proposed plans. The District Manager may require you to perform additional pressure tests.	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 and make them available to BSEE upon request.	0.75	1,340 results	1,005*
[721(g)(6)]	Contact the appropriate BSEE District Manager immediately if you have any indication of a failed negative pressure test; submit a description of the corrective action taken; and receive approval from the appropriate BSEE District Manager for the retest.	1	14 notifications	14*
[721(g)(8); 744(a)]	Submit Form BSEE–0125, EOR	Burden covered under 1014–0018		0
[722]	Caliper, pressure test, or evaluate casing; submit evaluation results report *including calculations;* obtain approval before *repairing or installing additional casing* [(including PE Certification.)]*;* or resuming operations (every 30 days during prolonged drilling).	3	247 reports	741*
[722(b)(3)]	[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: Immediately transmit real-time monitoring data onshore during operations or in HPHT reservoirs; store and monitor by qualified personnel.	[12]	[50 submittals]	[600]
[724(b)]	NEW: List designated location where real-time data will be stored and monitored in your APD or APM; make location and data accessible to BSEE upon request.	Burden covered under 1014–0025 for APD; and 1014–0026 for APM		0
Subtotal (G—Well Op.).			2,534 responses [500 responses] 3,034 responses	3,072 hours* [1,650 hours] 4,722 hours

BURDEN TABLE—Continued

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

30 CFR 250 Current *Revision* NEW	Reporting and recordkeeping requirement+ (BSEE-Approved Verification Organization = BAVO)	Hour burden	Average number of annual responses	Annual burden hours (rounded)
BOP System Requirements				
[730; 731; 732]	Submit BOP descriptions with your applicable APD or APM; third-party verification and supporting information/documentation.	Burden covered under 1014–0025 for APD; and 1014–0026 for APM		0
[730(a)(4)]	NEW: Maintain current set of approved schematic drawings on the rig and an onshore location; obtain District Manager approval to resume operations if any modifications or changes are made.	[24]	[10 requests]	[240]
[730(c)(1)]	NEW: Provide written report to manufacturer within 30 days of identifying equipment failure.	[2]	[30 reports]	[60]
[730(c)(2)]	NEW: Initiate investigation and analysis within 60 days to determine cause of equipment failure; provide the manufacturer a copy of analysis report.	[5]	[30 reports]	[150]
[730(c)(3)]	NEW: Report the design change/modified procedures in writing to BSEE, OORP; within 30 days of manufacturer's notification.	[5]	[2 reports]	[10]
[730(d)(2)]	NEW: Request for alternate to API Spec. Q1 to BSEE, OORP.	[5]	[1 response]	[5]
[731]	Resubmit BOP system component documentation in your APD or APM when information changes or moved off location from well.	Burden covered under 1014–0025 for APD; and 1014–0026 for APM.		0
[732(a)]	NEW: Submit all relevant information to nominate a verification organization for BSEE approval.	[5]	[5 submittals]	[25]
[732(b)]	NEW: Submit BAVO verification and all supporting documentation related to this section (such as, but not limited to sharing testing, pressure integrity testing, calculations, etc.).	[10]	[150 Verifications]	[1,500]
[732(c)]	NEW: Submit verifications showing the BAVO conducted a comprehensive review of the BOP and related equipment for HPHT wells as listed in this section; submit verifications to the District Manager and Regional Supervisor before beginning operations in an HPHT environment.	[10]	[10 wells]	[100]
[732(d), (e)]	NEW: Submit Mechanical Integrity Assessment Report (completed by a BAVO) to BSEE, OORP; report must include all requirements listed in this section; make all documentation available to BSEE upon request.	[10]	[90 reports]	[900]
[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 that any acoustic control system will function properly in proposed environment and conditions; *submit any additional information requested.*	5 *1*	1 validation *10 submittals*	5* *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 and LMRP and minimum knowledge requirements for personnel authorized to operate and maintain BOP components.	Burden covered under 1014–0018		0

BURDEN TABLE—Continued

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

30 CFR 250 Current *Revision* NEW	Reporting and recordkeeping requirement+ (BSEE-Approved Verification Organization = BAVO)	Hour burden	Average number of annual responses	Annual burden hours (rounded)
[734(b), (c)]	Submit a revised APD/APM with BAVO [documenting repairs; before drilling out surface casing]; 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), (d)(13)].	In your APD: submit stump, initial, or pressure tests; and subsea BOP procedures and supporting relevant data/information; indicate which casing string and liner met the criteria of this section; quick disconnect procedures with your deadman test procedures, etc. Obtain District Manager approval of appropriate test pressures; may require more frequent testing on your BOP; or if you test annular BOP less than 70 percent.	Burden covered under 1014–0025		0
[737(c); 746(a), (b), (c), (d)].	Record the time, date, and results of all pressure tests, actuations, and inspections of the BOP system, system components, and marine riser in the daily report; onsite representative 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) (d)(12);].	Notify District Manager at least 72 hours prior to pressure stump/initial tests on seafloor; if BSEE rep unable to witness test, provide results to BSEE within 72 hours after completion; document all ROV intervention function test results; make available to BSEE upon request.	0.25 5.5	186 notifications 1,239 results	47 * 6,815 *
[737(d)(13)]	Document all autoshear, *EDS,* and deadman on your subsea BOP systems function test results; make available to BSEE upon request.	0.5 *1*	2,520 submittals *120 responses*	1,260 * *120*
[737(e)]	Provide 72 hour advance notice of location of shearing ram tests or inspections; allow BSEE access to witness testing, inspections, and information verification.	0.25	136 notices	34 *
[738; 746(e)]	NEW/*Revised:* Requires District Manager Approval:	[0.5]	[25 requests]	[13]
	(a), (d); 746(e) Report problems, issues, leaks;.	[1]	[25 requests]	[25]
	(b) Put well in a safe condition;	[1]	[25 requests]	[25]
	(b) Prior to resuming operations for new/repaired/reconfigured BOP.	0.25	200 requests	50 *
	(*g) Your well control places demands above its rating pressure;*	*1*	*15 requests*	*15*
	(j) Two barriers in place prior to BOP removal.	[1]	[1 request]	[1]
[738(b), (i)]	NEW: Submit a report/verification from BAVO that BOP is fit for service if have to repair, replace, or reconfigure a BOP.	[0.5]	[50 submittals]	[25]
[738(f)]	NEW: Notify the District Manager of BOP configuration changes.	[0.5]	[15 submittals]	[8]
[738(g)]	NEW: Demonstrate your well-control procedures will not place demands above its rated working pressure.	[1]	[15 submittals]	[15]
[738(k)]	NEW: Contact District Manager for approval prior to latching up the BOP stack or reestablishing power.	[1]	[2 requests]	[2]

BURDEN TABLE—Continued

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

30 CFR 250 Current *Revision* NEW	Reporting and recordkeeping requirement+ (BSEE-Approved Verification Organization = BAVO)	Hour burden	Average number of annual responses	Annual burden hours (rounded)
[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 from District Manager to utilize any other well-control equipment; include report from BAVO on the 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 report to the District Manager prepared by BAVO describing failure of redundant control and confirming no impact to the BOP that makes it unfit for well control purposes; receive approval to continue operations; submit any additional information requested by the District Manager.	[1]	[15 submittals]	[15]
[739]	Document BOP maintenance and inspection procedures used; record results of BOP inspections and maintenance actions; maintain BOP records for 2 years or longer if directed on the rig; maintain design, maintenance, inspection, and repair records for the life of the equipment; make available to BSEE upon request.	9.75	350 records	3,413 *
[739(b)]	NEW: Assemble a detailed report compiled by a BAVO documenting the once every 5-year inspection, including any problems and corrections; make available to BSEE upon request.	[5]	[21 reports]	[105]
Subtotal (G—BOP SR).			9,122 responses *145 responses* [532 responses] 9,799 responses	46,216 hours * *145 hours* [3,244 hours] 49,605 hours
	Records and Reporting Requirement			
[740; 711(b); 738(c); 745; 746].	Maintain a daily report and accurate records for each well onsite during operation [such items in the daily report include, but are not limited to, [date, time, type of drill], test results, actuations, inspection of the BOP system, system component, signoff approvals, etc.]; and any information required by the District Manager.	25 min [1]	312 reports [25 responses]	130 * [25]
[740; 741]	Retain drilling records for 90 days after drilling is complete; retain casing/liner pressure, diverter, BOP tests [and real-time data monitoring] for 2 years; retain well completion/well workover until well is permanently plugged/abandoned or lease is assigned; the records must contain appropriate information and any other information required by the District Manager.	2.15 [1]	3,460 records [25 responses]	7,439 * [25]
[742] NTL	Record and submit well logs and surveys run in the wellbore and/or charts of well logging operations.	3	281 logs/surveys	843 *

BURDEN TABLE—Continued

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

30 CFR 250 Current *Revision* NEW	Reporting and recordkeeping requirement+ (BSEE-Approved Verification Organization = BAVO)	Hour burden	Average number of annual responses	Annual burden hours (rounded)
	Record and submit directional and vertical-well surveys..	1	281 reports	281 *
	Record and submit 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 case-by-case basis) 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 tests, actuations, and inspections at the facility; retain all the records listed in this section for a period of 2 years at the facility, at the lessee's field office nearest the OCS facility, or at another location conveniently available to BSEE; make all the records available to BSEE upon request.	1.5	1,563 records	2,345 *
Subtotal (G—Rec. & Rpt. Req.).			10,570 responses [50 responses] 10,620 responses	20,025 hours * [50 hours] 20,075 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 *Revised burden* [NEW burden]			52,235 responses *1,159 responses* [2,172 responses]	174,686 hours * *5,052 hours* [11,701 hours]
Grand Total			55,566 Responses	191,439 Hours

BURDEN TABLE—Continued

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

30 CFR 250 Current *Revision* NEW	Reporting and recordkeeping requirement+ (BSEE-Approved Verification Organization = BAVO)	Hour burden	Average number of annual responses	Annual burden hours (rounded)
			$102,500 Non-Hour Cost Burden	

* Indicates burdens are covered under one of the following OMB approved control numbers: 1014–0022, Subpart A; 1014–0024, Subpart B; 1014–0018, Subpart D; 1014–0004, Subpart E; 1014–0001, Subpart F; 1014–0006, Subpart P; 1014–0010, Subpart Q; 1014–0013, GPS for MODUs; 1014–0025, APDs; or 1014–0026, APMs.

+ In the future BSEE will be allowing the option of electronic reporting for certain requirements.

The BSEE specifically solicits comments on the following:

(1) Is the IC necessary or useful for us to perform properly;

(2) Is the proposed burden accurate;

(3) Do you have any suggestions that will enhance the quality, usefulness, and clarity of the information to be collected; and

(4) Can we minimize the burden on the respondents.

In addition, the PRA requires agencies to also estimate the non-hour cost burden to respondents or recordkeepers resulting from the collection of information. Therefore, if you have other than hour burden costs to generate, maintain, and disclose this information, you should comment and provide your total capital and startup cost components or annual operation, maintenance, and purchase of service components. Generally, your estimate should not include costs incurred for reasons other than to provide information or keep records for the government; or as part of customary and usual business or private practices. For further information on this burden, refer to 5 CFR 1320.3(b)(1) and (2), or contact the BSEE Bureau Information Collection Clearance Officer.

National Environmental Policy Act of 1969 (NEPA)

We prepared a draft environmental assessment that concludes that this proposed rule would not have a significant impact on the quality of the environment under NEPA. A copy of the draft Environmental Assessment can be viewed at *www.regulations.gov* (use the keyword/ID BSEE–2015–0002). We will consider any new information we receive during the public comment period for the proposed rule that may inform our analysis of the potential environmental impacts of the rule.

Data Quality Act

In developing this rule, we did not conduct or use a study, experiment, or survey requiring peer review under the Data Quality Act (Pub. L. 106–554, app. C § 515, 114 Stat. 2763, 2763A–153–154).

Effects on the Nation's Energy Supply (E.O. 13211)

This rule is not a significant energy action under the definition in E.O. 13211. Although the proposed rule is a significant regulatory action under E.O. 12866, it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. A Statement of Energy Effects is not required.

Clarity of This Regulation

We are required by E.O. 12866, E.O. 12988, and by the Presidential Memorandum of June 1, 1998, to write all rules in plain language. This means that each rule we publish must:

(1) Be logically organized;

(2) Use the active voice to address readers directly;

(3) Use clear language rather than jargon;

(4) Be divided into short sections and sentences; and

(5) Use lists and tables wherever possible.

If you feel that we have not met these requirements, send us comments by one of the methods listed in the **ADDRESSES** section. To better help us revise the rule, your comments should be as specific as possible. For example, you should tell us the numbers of the sections or paragraphs that you find unclear, which sections or sentences are too long, the sections where you feel lists or tables would be useful, *etc.*

Public Availability of Comments

Before including your address, phone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

List of Subjects in 30 CFR Part 250

Administrative practice and procedure, Continental shelf, Environmental impact statements, Environmental protection, Incorporation by reference, Oil and gas exploration, Penalties, Public lands—mineral resources, Public lands—rights-of-way, Reporting and recordkeeping requirements, Sulphur.

Dated: April 9, 2015.

Janice M. Schneider,

Assistant Secretary—Land and Minerals Management.

For the reasons stated in the preamble, the Bureau of Safety and Environmental Enforcement (BSEE) is proposing to amend 30 CFR part 250 as follows:

PART 250—OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF

■ 1. The authority citation for part 250 continues to read as follows:

Authority: 30 U.S.C. 1751, 31 U.S.C. 9701, 43 U.S.C. 1334.

■ 2. In § 250.102, revise paragraphs (b)(1) and (b)(11) through (13) and add paragraph (b)(19) to read as follows:

§ 250.102 What does this part do?

* * * * *

(b) * * *

TABLE—WHERE TO FIND INFORMATION FOR CONDUCTING OPERATIONS

For information about . . .	Refer to . . .
(1) Applications for permit to drill (APD)	30 CFR 250, subparts D and G.
* * * * *	* *
(11) Oil and gas well-completion operations	30 CFR 250, subparts E and G.
(12) Oil and gas well-workover operations	30 CFR 250, subparts F and G.
(13) Decommissioning activities	30 CFR 250, subparts G and Q.
* * * * *	* *
(19) Well operations and equipment	30 CFR 250, subpart G.

■ 3. Amend § 250.107 by:

■ a. Removing the word "and" from the end of paragraph (a)(1);

■ b. Removing the period from the end of paragraph (a)(2) and adding in its place a semicolon; and

■ c. Adding paragraphs (a)(3) and (4) and (e).

The additions read as follows:

§ 250.107 What must I do to protect health, safety, property, and the environment?

(a) * * *

(3) Utilizing recognized engineering practices that reduce risks to the lowest level practicable when conducting design, fabrication, installation, operation, inspection, repair, and maintenance activities; and

(4) Complying with all lease, plan, and permit terms and conditions.

* * * * *

(e) The BSEE may issue orders to ensure compliance with this part, including but not limited to, orders to produce and submit records and to inspect, repair, and or replace equipment. The BSEE may also issue orders to shut-in operations of a component or facility because of a threat of serious, irreparable, or immediate harm to health, safety, property, or the environment posed by those operations or because the operations violate law, including a regulation, order, or provision of a lease, plan, or permit.

■ 4. In § 250.125, revise the table in paragraph (a) to read as follows:

§ 250.125 Service fees.

(a) * * *

Service—processing of the following:	Fee amount	30 CFR citation
(1) Suspension of Operations/Suspension of Production (SOO/SOP) Request.	$2,123	§ 250.171(e).
(2) Deepwater Operations Plan (DWOP)	$3,599	§ 250.292(q).
(3) Application for Permit to Drill (APD); Form BSEE–0123.	$2,113 *for initial applications only; no fee for revisions*	§ 250.410(d); § 250.513(b); § 250.1617(a).
(4) Application for Permit to Modify (APM); Form BSEE–0124.	$125	§ 250.465(b); § 250.513(b); § 250.613(b); § 250.1618(a); § 250.1704(g).
(5) New Facility Production Safety System Application for facility with more than 125 components.	$5,426 A component is a piece of equipment or ancillary system that is protected by one or more of the safety devices required by API RP 14C (as incorporated by reference in § 250.198); $14,280 additional fee will be charged if BSEE deems it necessary to visit a facility offshore, and $7,426 to visit a facility in a shipyard.	§ 250.802(e).
(6) New Facility Production Safety System Application for facility with 25–125 components.	$1,314 Additional fee of $8,967 will be charged if BSEE deems it necessary to visit a facility offshore, and $5,141 to visit a facility in a shipyard.	§ 250.802(e).
(7) New Facility Production Safety System Application for facility with fewer than 25 components.	$652	§ 250.802(e).
(8) Production Safety System Application—Modification with more than 125 components reviewed.	$605	§ 250.802(e).
(9) Production Safety System Application—Modification with 25–125 components reviewed.	$217	§ 250.802(e).
(10) Production Safety System Application—Modification with fewer than 25 components reviewed.	$92	§ 250.802(e).
(11) Platform Application—Installation—Under the Platform Verification Program.	$22,734	§ 250.905(l).
(12) Platform Application—Installation—Fixed Structure Under the Platform Approval Program.	$3,256	§ 250.905(l).
(13) Platform Application—Installation—Caisson/Well Protector.	$1,657	§ 250.905(l)
(14) Platform Application—Modification/Repair	$3,884	§ 250.905(l).
(15) New Pipeline Application (Lease Term)	$3,541	§ 250.1000(b).
(16) Pipeline Application—Modification (Lease Term)	$2,056	§ 250.1000(b).
(17) Pipeline Application—Modification (ROW)	$4,169	§ 250.1000(b).
(18) Pipeline Repair Notification	$388	§ 250.1008(e).
(19) Pipeline Right-of-Way (ROW) Grant Application	$2,771	§ 250.1015(a).
(20) Pipeline Conversion of Lease Term to ROW	$236	§ 250.1015(a).
(21) Pipeline ROW Assignment	$201	§ 250.1018(b).

Service—processing of the following:	Fee amount	30 CFR citation
(22) 500 Feet From Lease/Unit Line Production Request	$3,892	§ 250.1156(a).
(23) Gas Cap Production Request	$4,953	§ 250.1157.
(24) Downhole Commingling Request	$5,779	§ 250.1158(a).
(25) Complex Surface Commingling and Measurement Application.	$4,056	§ 250.1202(a); § 250.1203(b); § 250.1204(a).
(26) Simple Surface Commingling and Measurement Application.	$1,371	§ 250.1202(a); § 250.1203(b); § 250.1204(a).
(27) Voluntary Unitization Proposal or Unit Expansion	$12,619	§ 250.1303(d).
(28) Unitization Revision	$896	§ 250.1303(d).
(29) Application to Remove a Platform or Other Facility	$4,684	§ 250.1727.
(30) Application to Decommission a Pipeline (Lease Term).	$1,142	§ 250.1751(a) or § 250.1752(a).
(31) Application to Decommission a Pipeline (ROW)	$2,170	§ 250.1751(a) or § 250.1752(a).

■ 5. Amend § 250.198 by revising paragraphs (h)(51), (63), (68), and (70) and adding paragraphs (h)(89) through (94) to read as follows:

§ 250.198 Documents incorporated by reference.

* * * * *

(h) * * *

(51) API RP 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), First Edition, June 1998; Reaffirmed May 2006, Errata June 2009; incorporated by reference at §§ 250.292, 250.733, 250.800, 250.901, and 250.1002;

* * * * *

(63) API Standard 53, Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition, November 2012; incorporated by reference at §§ 250.730, 250.737, and 250.739;

* * * * *

(68) ANSI/API Spec. Q1, Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry, ISO TS 29001:2007 (Identical), Petroleum, petrochemical and natural gas industries—Sector specific requirements—Requirements for product and service supply organizations, Eighth Edition, December 2007, Effective Date: June 15, 2008; incorporated by reference at §§ 250.730 and 250.806;

* * * * *

(70) ANSI/API Spec. 6A, Specification for Wellhead and Christmas Tree Equipment, Nineteenth Edition, July 2004; Effective Date: February 1, 2005; Contains API Monogram Annex as Part of U.S. National Adoption; ISO 10423:2003 (Modified), Petroleum and natural gas industries—Drilling and production equipment—Wellhead and Christmas tree equipment; Errata 1, September 2004, Errata 2, April 2005, Errata 3, June 2006, Errata 4, August 2007, Errata 5, May 2009; Addendum 1, February 2008; Addendum 2, 3, and 4, December 2008; incorporated by reference at §§ 250.730, 250.806, and 250.1002;

* * * * *

(89) ANSI/API Spec. 11D1, Packers and Bridge Plugs, ISO 14310:2008 (Identical), Petroleum and natural gas industries—Downhole equipment—Packers and bridge plugs, Second Edition, Effective Date: January 1, 2010; incorporated by reference at §§ 250.518, 250.619, and 250.1703;

(90) ANSI/API Spec. 16A, Specification for Drill-through Equipment, Third Edition, June 2004; incorporated by reference at § 250.730;

(91) ANSI/API Spec. 16C, Specification for Choke and Kill Systems, First Edition, January 1993; incorporated by reference at § 250.730;

(92) API Spec. 16D, Specification for Control Systems for Drilling Well control Equipment and Control Systems for Diverter Equipment, Second Edition, July 2004; incorporated by reference at § 250.730;

(93) ANSI/API Spec. 17D, Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment, Second Edition; May 2011; ISO 13628–4 (Identical), Design and operation of subsea production systems-Part 4: Subsea wellhead and tree equipment; incorporated by reference at § 250.730; and

(94) ANSI/API RP 17H, Remotely Operated Vehicle Interfaces on Subsea Production Systems, ISO 13628–8:2002 (Identical), Petroleum and natural gas industries—Design and operation of subsea production systems—Part 8: Remotely Operated Vehicle (ROV) interfaces on subsea production systems, First Edition, July 2004, Reaffirmed: January 2009; incorporated by reference at § 250.734.

* * * * *

■ 6. In § 250.199, revise paragraph (e) to read as follows:

§ 250.199 Paperwork Reduction Act statements—information collection.

* * * * *

(e) BSEE is collecting this information for the reasons given in the following table:

30 CFR subpart, title and/or BSEE Form (OMB Control No.)	BSEE collects this information and uses it to:
(1) Subpart A, General (1014–0022), including Forms BSEE–0132, Evacuation Statistics; BSEE–0143, Facility/Equipment Damage Report; BSEE–1832, Notification of Incidents of Noncompliance.	(i) Determine that activities on the OCS comply with statutory and regulatory requirements; are safe and protect the environment; and result in diligent development and production on OCS leases. (ii) Support the unproved and proved reserve estimation, resource assessment, and fair market value determinations. (iii) Assess damage and project any disruption of oil and gas production from the OCS after a major natural occurrence.
(2) Subpart B, Plans and Information (1014–0024)	Evaluate Deepwater Operations Plans for compliance with statutory and regulatory requirements.

30 CFR subpart, title and/or BSEE Form (OMB Control No.)	BSEE collects this information and uses it to:
(3) Subpart C, Pollution Prevention and Control (1014–0023)	(i) Evaluate measures to prevent unauthorized discharge of pollutants into the offshore waters. (ii) Ensure action is taken to control pollution.
(4) Subpart D, Oil and Gas and Drilling Operations (1014–0018), including Forms BSEE–0125, End of Operations Report; BSEE–0133, Well Activity Report; and BSEE–0133S, Open Hole Data Report.	(i) Evaluate the equipment and procedures to be used in drilling operations on the OCS. (ii) Ensure that drilling operations meet statutory and regulatory requirements.
(5) Subpart E, Oil and Gas Well-Completion Operations (1014–0004)	(i) Evaluate the equipment and procedures to be used in well-completion operations on the OCS. (ii) Ensure that well-completion operations meet statutory and regulatory requirements.
(6) Subpart F, Oil and Gas Well Workover Operations (1014–0001)	(i) Evaluate the equipment and procedures to be used during well-workover operations on the OCS. (ii) Ensure that well-workover operations meet statutory and regulatory requirements.
(7) Subpart G, Blowout Preventer Systems (1014-xxxx), including Form BSEE–0144, Rig Movement Notification Report.	(i) Evaluate the equipment and procedures to be used during well drilling, completion, workover, and abandonment operations on the OCS. (ii) Ensure that well operations meet statutory and regulatory requirements.
(8) Subpart H, Oil and Gas Production Safety Systems (1014–0003)	(i) Evaluate the equipment and procedures that will be used during production operations on the OCS. (ii) Ensure that production operations meet statutory and regulatory requirements.
(9) Subpart I, Platforms and Structures (1014–0011)	(i) Evaluate the design, fabrication, and installation of platforms on the OCS. (ii) Ensure the structural integrity of platforms installed on the OCS.
(10) Subpart J, Pipelines and Pipeline Rights-of-Way (1014–0016), including Form BSEE–0149, Assignment of Federal OCS Pipeline Right-of-Way Grant.	(i) Evaluate the design, installation, and operation of pipelines on the OCS. (ii) Ensure that pipeline operations meet statutory and regulatory requirements.
(11) Subpart K, Oil and Gas Production Rates (1014–0019), including Forms BSEE–0126, Well Potential Test Report and BSEE–0128, Semiannual Well Test Report.	(i) Evaluate production rates for hydrocarbons produced on the OCS. (ii) Ensure economic maximization of ultimate hydrocarbon recovery.
(12) Subpart L, Oil and Gas Production Measurement, Surface Commingling, and Security (1014–0002).	(i) Evaluate the measurement of production, commingling of hydrocarbons, and site security plans. (ii) Ensure that produced hydrocarbons are measured and commingled to provide for accurate royalty payments and security.
(13) Subpart M, Unitization (1014–0015)	(i) Evaluate the unitization of leases. (ii) Ensure that unitization prevents waste, conserves natural resources, and protects correlative rights.
(14) Subpart N, Remedies and Penalties	(The requirements in subpart N are exempt from the Paperwork Reduction Act of 1995 according to 5 CFR 1320.4).
(15) Subpart O, Well Control and Production Safety Training (1014–0008).	(i) Evaluate training program curricula for OCS workers, course schedules, and attendance. (ii) Ensure that training programs are technically accurate and sufficient to meet statutory and regulatory requirements, and that workers are properly trained.
(16) Subpart P, Sulphur Operations (1014–0006)	(i) Evaluate sulphur exploration and development operations on the OCS. (ii) Ensure that OCS sulphur operations meet statutory and regulatory requirements and will result in diligent development and production of sulphur leases.
(17) Subpart Q, Decommissioning Activities (1014–0010)	Ensure that decommissioning activities, site clearance, and platform or pipeline removal are properly performed to meet statutory and regulatory requirements and do not conflict with other users of the OCS.
(18) Subpart S, Safety and Environmental Management Systems (1014–0017), including Form BSEE–0131, Performance Measures Data.	(i) Evaluate operators' policies and procedures to assure safety and environmental protection while conducting OCS operations (including those operations conducted by contractor and subcontractor personnel). (ii) Evaluate Performance Measures Data relating to risk and number of accidents, injuries, and oil spills during OCS activities.
(19) Application for Permit to Drill (APD, Revised APD), Form BSEE–0123; and Supplemental APD Information Sheet, Form BSEE–0123S, and all supporting documentation (1014–0025).	(i) Evaluate and approve the adequacy of the equipment, materials, and/or procedures that the lessee or operator plans to use during drilling. (ii) Ensure that applicable OCS operations meet statutory and regulatory requirements.

30 CFR subpart, title and/or BSEE Form (OMB Control No.)	BSEE collects this information and uses it to:
(20) Application for Permit to Modify (APM), Form BSEE–0124, and supporting documentation (1014–0026).	(i) Evaluate and approve the adequacy of the equipment, materials, and/or procedures that the lessee or operator plans to use during drilling and to evaluate well plan modifications and changes in major equipment. (ii) Ensure that applicable OCS operations meet statutory and regulatory requirements.

■ 7. Amend § 250.292 by:

■ a. Removing the word ''and'' from the end of paragraph (o);

■ b. Redesignating paragraph (p) as (q); and

■ c. Adding new paragraph (p).

The addition reads as follows:

§ 250.292 What must the DWOP contain?

* * * * *

(p) If you propose to use a pipeline free standing hybrid riser (FSHR) that utilizes a critical chain, wire rope, or synthetic tether to connect the top of the riser to a buoyancy air can, provide the following information in your DWOP in the discussions required by paragraphs (f) and (g) of this section:

(1) A detailed description and drawings of the FSHR, buoy and the tether system;

(2) Detailed information on the design, fabrication, and installation of the FSHR, buoy and tether system, including pressure ratings, fatigue life, and yield strengths;

(3) A description of how you met the design requirements, load cases, and allowable stresses for each load case according to API RP 2RD (as incorporated by reference in § 250.198);

(4) Detailed information regarding the tether system used to connect the FSHR to a buoyancy air can;

(5) Descriptions of your monitoring system and monitoring plan to monitor the pipeline FSHR and tether for fatigue, stress, and any other abnormal condition (*e.g.,* corrosion) that may negatively impact the riser or tether; and

(6) Documentation that the tether system and connection accessories for the pipeline FSHR have been certified by an approved classification society or equivalent and verified by the CVA required in Subpart I; and

* * * * *

■ 8. Revise § 250.400 to read as follows:

§ 250.400 General Requirements.

Drilling operations must be conducted in a safe manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the Outer Continental Shelf (OCS), including any mineral deposits (in areas leased and not leased), the National security or defense, or the marine, coastal, or human environment. In addition to the requirements of this subpart, you must also follow the applicable requirements of Subpart G.

§§ 250.401 through 250.403 [Removed and Reserved]

■ 9a. Remove and reserve §§ 250.401 through 250.403, and 250.406.

§ 250.406 [Removed and Reserved]

■ 9b. Remove and reserve § 250.406.

■ 10. Revise § 250.411 to read as follows:

§ 250.411 What information must I submit with my application?

In addition to forms BSEE–0123 and BSEE–0123S, you must include the information required in this subpart and Subpart G, including the following:

Information that you must include with an APD	Where to find a description
(a) Plat that shows locations of the proposed well	§ 250.412
(b) Design criteria used for the proposed well	§ 250.413
(c) Drilling prognosis	§ 250.414
(d) Casing and cementing programs	§ 250.415
(e) Diverter systems descriptions	§ 250.416
(f) BOP system descriptions	§ 250.731
(g) Requirements for using an MODU, and	§ 250.713
(h) Additional information	§ 250.418

■ 11. In § 250.413, revise paragraph (g) to read as follows:

§ 250.413 What must my description of well drilling design criteria address?

* * * * *

(g) A single plot containing curves for estimated pore pressures, formation fracture gradients, proposed drilling fluid weights, maximum equivalent circulating density, and casing setting depths in true vertical measurements;

* * * * *

■ 12. Amend § 250.414 by revising paragraphs (c), (h), and (i) and adding paragraphs (j) and (k) to read as follows:

§ 250.414 What must my drilling prognosis include?

* * * * *

(c) Planned safe drilling margins between proposed drilling fluid weights and the estimated pore pressures, and proposed drilling fluid weights and the lesser of estimated fracture gradients or casing shoe pressure integrity test. Your safe drilling margins must meet the following conditions:

(1) Static downhole mud weight must be greater than estimated pore pressure;

(2) Static downhole mud weight must be a minimum of one-half pound per gallon below the lesser of the casing shoe pressure integrity test or the lowest estimated fracture gradient;

(3) The equivalent circulating density must be below the lesser of the casing shoe pressure integrity test or the lowest estimated fracture gradient; and

(4) When determining the pore pressure and lowest estimated fracture gradient for a specific interval, you must consider related hole behavior observations.

* * * * *

(h) A list and description of all requests for using alternate procedures or departures from the requirements of this subpart in one place in the APD. You must explain how the alternate procedures afford an equal or greater degree of protection, safety, or performance, or why the departures are requested;

(i) Projected plans for well testing (refer to § 250.460);

(j) The type of wellhead system and liner hanger system to be installed and a descriptive schematic, which includes but is not limited to pressure ratings, dimensions, valves, load shoulders, and locking mechanisms, if applicable; and

(k) Any additional information required by the District Manager.

■ 13. In § 250.415, revise paragraph (a) to read as follows:

§ 250.415 What must my casing and cementing programs include?

* * * * *

(a) The following well design information:

(1) Hole sizes;

(2) Bit depths (including measured and true vertical depth (TVD));

(3) Casing information including sizes, weights, grades, collapse and burst values, types of connection, and

setting depths (measured and TVD) for all sections of each casing interval; and

(4) Locations of any installed rupture disks (indicate if burst or collapse and rating);

* * * * *

■ 14. Revise § 250.416 to read as follows:

§ 250.416 What must I include in the diverter description?

You must include in the diverter descriptions:

(a) A description of the diverter system and its operating procedures;

(b) A schematic drawing of the diverter system (plan and elevation views) that shows:

(1) The size of the annular BOP installed in the diverter housing;

(2) Spool outlet internal diameter(s);

(3) Diverter-line lengths and diameters; burst strengths and radius of curvature at each turn; and

(4) Valve type, size working pressure rating, and location.

§ 250.417 [Removed and Reserved]

■ 15. Remove and reserve § 250.417.

■ 16. In § 250.418, revise paragraph (g) to read as follows:

§ 250.418 What additional information must I submit with my APD?

* * * * *

(g) A request for approval if you plan to wash out or displace cement to facilitate casing removal upon well abandonment. Your request must include a description of how far below the mudline you propose to displace cement and how you will visually monitor returns;

* * * * *

■ 17. Amend § 250.420 by:

■ a. Revising the introductory text and paragraph (a)(5);

■ b. Redesignating paragraph (a)(6) as (a)(7);

■ c. Adding new paragraph (a)(6) and paragraph (b)(4); and

■ d. Revising paragraph (c).

The revisions and additions read as follows:

§ 250.420 What well casing and cementing requirements must I meet?

You must case and cement all wells. Your casing and cementing programs must meet the applicable requirements of this subpart and of subpart G.

(a) * * *

(5) Support unconsolidated sediments;

(6) Provide adequate centralization to ensure proper cementation; and

* * * * *

(b) * * *

(4) If you need to substitute a different size, grade, or weight of casing than what was approved in your APD, you must contact the District Manager for approval prior to installing the casing.

* * * * *

(c) *Cementing requirements.* (1) You must design and conduct your cementing jobs so that cement composition, placement techniques, and waiting times ensure that the cement placed behind the bottom 500 feet of casing attains a minimum compressive strength of 500 psi before drilling out the casing or before commencing completion operations.

(2) You must use a weighted fluid to maintain an overbalanced hydrostatic pressure during the cement setting time, except when cementing casings or liners in riserless hole sections.

■ 18. In § 250.421, revise paragraphs (b) and (f) to read as follows:

§ 250.421 What are the casing and cementing requirements by type of casing string?

* * * * *

Casing type	Casing requirements	Cementing requirements
*	* * *	* * *
(b) Conductor ...	Design casing and select setting depths based on relevant engineering and geologic factors. These factors include the presence or absence of hydrocarbons, potential hazards, and water depths. Set casing immediately before drilling into formations known to contain oil or gas. If you encounter oil or gas or unexpected formation pressure before the planned casing point, you must set casing immediately and set it above the encountered zone.	Use enough cement to fill the calculated annular space back to the mudline. Verify annular fill by observing cement returns. If you cannot observe cement returns, use additional cement to ensure fill-back to the mudline. For drilling on an artificial island or when using a well cellar, you must discuss the cement fill level with the District Manager.
*	* * *	* * *
(f) Liners	If you use a liner as surface casing, you must set the top of the liner at least 200 feet above the previous casing/liner shoe. If you use a liner as an intermediate string below a surface string or production casing below an intermediate string, you must set the top of the liner at least 100 feet above the previous casing shoe. You may not use a liner as conductor casing	Same as cementing requirements for specific casing types. For example, a liner used as intermediate casing must be cemented according to the cementing requirements for intermediate casing.

■ 19. Revise § 250.423 to read as follows:

§ 250.423 What are the requirements for casing and liner installation?

You must ensure proper installation of casing in the subsea wellhead or liner in the liner hanger.

(a) You must ensure that the latching mechanisms or lock down mechanisms are engaged upon successfully installing and cementing the casing string.

(b) If you run a liner that has a latching mechanism or lock down mechanism, you must ensure that the latching mechanisms or lock down mechanisms are engaged upon successfully installing and cementing the liner.

(c) You must perform a pressure test on the casing seal assembly to ensure proper installation of casing or liner. You must perform this test for the intermediate and production casing strings or liners.

(1) You must submit for approval with your APD, test procedures and criteria for a successful test.

(2) You must document all your test results and make them available to BSEE upon request.

§§ 250.424 through 250.426 [Removed and Reserved]

■ 20. Remove and reserve §§ 250.424 through 250.426.

■ 21. In § 250.427, revise paragraph (b) to read as follows:

§ 250.427 What are the requirements for pressure integrity tests?

* * * * *

(b) While drilling, you must maintain the safe drilling margins identified in § 250.414. When you cannot maintain the safe margins, you must suspend drilling operations and remedy the situation.

■ 22. In § 250.428, revise paragraphs (b) through (d) and add paragraph (k) to read as follows:

§ 250.428 What must I do in certain cementing and casing situations?

* * * * *

If you encounter the following situation:	Then you must . . .
* * *	* * * *
(b) Need to change casing setting depths or hole interval drilling depth (for a BHA with an under-reamer, this means bit depth) more than 100 feet true vertical depth (TVD) from the approved APD due to conditions encountered during drilling operations.	Submit those changes to the District Manager for approval and include a certification by a professional engineer (PE) that he or she reviewed and approved the proposed changes.
(c) Have indication of inadequate cement job (such as lost returns, no cement returns to mudline or expected height, cement channeling, or failure of equipment).	(1) Locate the top of cement by: (i) Running a temperature survey; (ii) Running a cement evaluation log; or (iii) Using a combination of these techniques. (2) Determine if your cement job is inadequate. If your cement job is determined to be inadequate, refer to paragraph (d) of this section. (3) If your cement job is determined to be adequate, report the results to the District Manager in your submitted WAR.
(d) Inadequate cement job	Take remedial actions. The District Manager must review and approve all remedial actions before you may take them, unless immediate actions must be taken to ensure the safety of the crew or to prevent a well-control event. If you complete any immediate action to ensure the safety of the crew or to prevent a well-control event, submit a description of the action to the District Manager when that action is complete. Any changes to the well program will require submittal of a certification by a professional engineer (PE) certifying that he or she reviewed and approved the proposed changes, and must meet any other requirements of the District Manager.
* * *	* * * *
(k) Plan to use a valve on the drive pipe during cementing operations for the conductor casing, surface casing, or liner.	Include a description of the plan in your APD. Your description must include a schematic of the valve and height above the water line. The valve must be remotely operated and full opening with visual observation while taking returns. The person in charge of observing returns must be in communication with the drill floor. You must record in your daily report and in the WAR if cement returns were observed. If cement returns are not observed, you must contact the District Manager and obtain approval of proposed plans to locate the top of cement before continuing with operations.

§§ 250.440 through 250.451 [Removed and Reserved]

■ 23. Remove the undesignated center heading ''Blowout Preventer (BOP) System Requirements'' and remove and reserve §§ 250.440 through 250.451.

§ 250.456 [Amended]

■ 24. Amend § 250.456:

■ a. In paragraph (i), by adding the word ''and'' after the semi-colon

■ b. By removing paragraph (j); and

■ c. By redesignating paragraph (k) as (j).

■ 25. Revise § 250.462 to read as follows.

§ 250.462 What are the source control and containment requirements?

For drilling operations using a subsea BOP or surface BOP on a floating facility, you must have the ability to control or contain a blowout event at the sea floor.

(a) To determine your required source control and containment capabilities you must do the following:

(1) Consider a scenario of the wellbore fully evacuated to reservoir fluids, with no restrictions in the well.

(2) Evaluate the performance of the well as designed to determine if a full shut-in can be achieved without having reservoir fluids broach to the sea floor. If your evaluation indicates that the well can only be partially shut-in, then you must determine your ability to flow and capture the residual fluids to a surface production and storage system.

(b) You must have access to and ability to deploy Source Control and Containment Equipment (SCCE) necessary to regain control of the well. SCCE means the capping stack, cap and flow system, containment dome, and/or other subsea and surface devices, equipment, and vessels whose collective purpose is to control a spill source and stop the flow of fluids into the environment or to contain fluids escaping into the environment. This equipment must include, but is not limited to, the following:

(1) Subsea containment and capture equipment, including containment domes and capping stacks;

(2) Subsea utility equipment, including hydraulic power, hydrate control, and dispersant injection equipment;

(3) Riser systems;

(4) Remotely operated vehicles (ROVs);

(5) Capture vessels;

(6) Support vessels; and

(7) Storage facilities.

(c) You must submit a description of your source control and containment capabilities to the Regional Supervisor and receive approval before BSEE will approve your APD, Form BSEE–0123. The description of your containment capabilities must contain the following:

(1) Your source control and containment capabilities for controlling and containing a blowout event at the seafloor,

(2) A discussion of the determination required in paragraph (a) of this section, and

(3) Information showing that you have access to and ability to deploy all equipment required by paragraph (b) of this section.

(d) You must contact the District Manager and Regional Supervisor for reevaluation of your source control and containment capabilities if your:

(1) Well design changes, or

(2) Approved source control and containment equipment is out of service.

(e) You must maintain, test, and inspect the source control and containment equipment identified in the following table according to these requirements:

Equipment	Requirements, you must:	Additional information
(1) Capping stacks	(i) Function test all pressure holding critical components on a quarterly frequency (not to exceed 104 days between tests).	Pressure holding critical components are those components that will experience wellbore pressure during a shut-in after being functioned.
	(ii) Pressure test pressure holding critical components on a bi-annual basis, but not later than 210 days from the last pressure test. All pressure testing must be witnessed by BSEE and a BSEE- approved verification organization.	Pressure holding critical components are those components that will experience wellbore pressure during a shut-in. These components include, but are not limited to: All blind rams, wellhead connectors, and outlet valves.
	(iii) Notify BSEE at least 21 days prior to commencing any pressure testing.	
(2) Production Safety Systems used for flow and capture operations.	(i) Meet or exceed the requirements set forth in 30 CFR 250.800–250.808, Subpart H.	
	(ii) Have all equipment unique to containment operations available for inspection at all times..	
(3) Subsea utility equipment	Have all equipment unique to containment operations available for inspection at all times.	Subsea utility equipment includes, but is not limited to: Hydraulic power sources, debris removal, hydrate control equipment, and dispersant injection equipment.

■ 26. In § 250.465, revise paragraph (b)(3) to read as follows:

§ 250.465 When must I submit an Application for Permit to Modify (APM) or an End of Operations Report to BSEE?

* * * * *

(b) * * *

(3) Within 30 days after completing this work, you must submit an End of Operations Report (EOR), Form BSEE–0125, as required under § 250.744.

§§ 250.466 through 250.469 [Removed and Reserved]

■ 27. Remove and reserve §§ 250.466 through 250.469.

■ 28. Revise § 250.500 to read as follows:

§ 250.500 General requirements.

Well-completion operations must be conducted in a manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the OCS, including any mineral deposits (in areas leased and not leased), the National security or defense, or the marine, coastal, or human environment. In addition to the requirements of this subpart, you must also follow the applicable requirements of Subpart G.

§§ 250.502 and 250.506 [Removed and Reserved]

■ 29. Remove and reserve §§ 250.502 and 250.506.

§ 250.514 [Amended]

■ 30. In § 250.514, remove paragraph (d).

§§ 250.515 through 250.517 [Removed and Reserved]

■ 31. Remove and reserve §§ 250.515 through 250.517.

■ 32. Amend § 250.518 by:

■ a. Removing paragraph (b);

■ b. Redesignating paragraphs (c) through (e) as paragraphs (b) through (d); and

■ c. Adding new paragraph (e) and paragraph (f).

The additions read as follows:

§ 250.518 Tubing and wellhead equipment.

* * * * *

(e) Installed packers and bridge plugs must meet the following:

(1) All packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198);

(2) During well completion operations, 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;

(3) The production packer must be set as close as practically possible to the perforated interval; and

(4) The production packer must be set at a depth that is within the cemented interval of the selected casing section.

(f) Your APM must include a description and calculations for how you determined the production packer setting depth.

■ 33. Revise § 250.600 to read as follows:

§ 250.600 General requirements.

Well-workover operations must be conducted in a manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the Outer Continental Shelf (OCS) including any mineral deposits (in areas leased and not leased), the National security or defense, or the marine, coastal, or human environment. In addition to the requirements of this subpart, you must also follow the applicable requirements of subpart G.

§ 250.602 [Removed and Reserved]

■ 34a. Remove and reserve § 250.602.

§ 250.606 [Removed and Reserved]

■ 34b. Remove and reserve § 250.606.

§ 250.614 [Amended]

■ 35. In § 250.614, remove paragraph (d).

§ 250.615 [Removed and Reserved]

■ 36. Remove and reserve § 250.615.

■ 37. Amend § 250.616 by:

■ a. Revising the section heading;

■ b. Removing paragraphs (a) through (e); and

■ c. Redesignating paragraphs (f) through (h) as paragraphs (a) through (c).

The revision reads as follows:

§ 250.616 Coiled tubing and snubbing operations.

* * * * *

§§ 250.617 and 250.618 [Removed and Reserved]

■ 38. Remove and reserve §§ 250.617 and 250.618.

■ 39. Amend § 250.619 by:

■ a. Removing paragraph (b);

■ b. Redesignating paragraphs (c) through (e) as paragraphs (b) through (d); and

■ c. Adding new paragraph (e) and paragraph (f).

The additions read as follows;

§ 250.619 Tubing and wellhead equipment.

* * * * *

(e) If you pull and reinstall packers and bridge plugs, you must meet the following:

(1) All packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198);

(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 during well completion operations that will exert a hydrostatic force greater than or equal to the force created by the reservoir pressure below the packer;

(3) The production packer must be set as close as practically possible to the perforated interval; and

(4) The production packer must be set at a depth that is within the cemented interval of the selected casing section.

(f) Your APM must include a description and calculations for how you determined the production packer setting depth.

■ 40. Add subpart G to read as follows:

Subpart G—Well Operations and Equipment

General Requirements

Sec.

Rig Requirements

Well Operations

Blowout Preventer (BOP) System Requirements

Records and Reporting

Subpart G—Well Operations and Equipment

General Requirements

§ 250.700 What operations and equipment does this subpart cover?

This subpart covers operations and equipment associated with drilling, completion, workover, and decommissioning activities. This subpart includes regulations applicable to drilling, completion, workover, and decommissioning activities in addition to applicable regulations contained in subparts D, E, F, and Q of this part unless explicitly stated otherwise.

§ 250.701 May I use alternate procedures or equipment during operations?

You may use alternate procedures or equipment during operations after receiving approval as described in § 250.141 of this part. You must identify and discuss your proposed alternate procedures or equipment in your Application for Permit to Drill (APD) (Form BSEE–0123) (see § 250.414(h)) or your Application for Permit to Modify (APM) (Form BSEE–0124). Procedures for obtaining approval of alternate procedures or equipment are described in § 250.141 of this part.

§ 250.702 May I obtain departures from these requirements?

You may apply for a departure from these requirements as described in § 250.142. Your request must include a justification showing why the departure is necessary. You must identify and discuss the departure you are requesting in your APD (see § 250.414(h)) or your APM.

§ 250.703 What must I do to keep wells under control?

You must take the necessary precautions to keep wells under control at all times, including:

(a) Use recognized engineering practices that reduce risks to the lowest level practicable when monitoring and evaluating well conditions and to minimize the potential for the well to flow or kick;

(b) Have a person onsite during operations who represents your interests and can fulfill your responsibilities;

(c) Ensure that the toolpusher, operator's representative, or a member of the rig crew maintains continuous surveillance on the rig floor from the beginning of operations until the well is completed or abandoned, unless you have secured the well with blowout preventers (BOPs), bridge plugs, cement plugs, or packers;

(d) Use personnel trained according to the provisions of Subparts O and S;

(e) Use and maintain equipment and materials necessary to ensure the safety and protection of personnel, equipment, natural resources, and the environment; and

(f) Use equipment that has been designed, tested, and rated for the most extreme service conditions to which it will be exposed while in service.

Rig Requirements

§ 250.710 What instructions must be given to personnel engaged in well operations?

Prior to engaging in well operations, personnel must be instructed in:

(a) *Date and time of safety meetings.* The safety requirements for the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment as required by subpart S of this part. Date and time of safety meetings must be recorded and available at the facility for review by BSEE representatives.

(b) *Well control.* You must prepare a well-control plan for each well. Each well-control plan must contain instructions for personnel about the use of each well-control component of your BOP, procedures that describe how personnel will seal the wellbore and shear pipe before maximum anticipated surface pressure (MASP) conditions are exceeded, assignments for each crew member, and a schedule for completion of each assignment. You must keep a copy of your well-control plan on the rig at all times, and make it available to BSEE upon request. You must post a copy of the well-control plan on the rig floor.

§ 250.711 What are the requirements for well-control drills?

You must conduct a weekly well-control drill with all personnel engaged in well operations. Your drill must familiarize personnel engaged in well operations with their roles and functions so that they can perform their duties promptly and efficiently as outlined in the well-control plan required by § 250.710.

(a) *Timing of drills.* You must conduct each drill during a period of activity that minimizes the risk to operations. The timing of your drills must cover a range of different operations, including drilling with a diverter, on-bottom drilling, and tripping. The same drill may not be repeated consecutively.

(b) *Recordkeeping requirements.* For each drill, you must record the following in the daily report:

(1) Date, time, and type of drill conducted;

(2) The amount of time it took to be ready to close the diverter or use each well-control component of BOP system; and

(3) The total time to complete the entire drill.

(c) *A BSEE ordered drill.* A BSEE representative may require you to conduct a well-control drill during a BSEE inspection. The BSEE representative will consult with your onsite representative before requiring the drill.

§ 250.712 What rig unit movements must I report?

(a) You must report the movement of all rig units on and off locations to the District Manager using Form BSEE–0144, Rig Movement Notification Report. Rig units include MODUs, platform rigs, snubbing units, wire-line units used for non-routine operations, and coiled tubing units. You must inform the District Manager 72 hours before:

(1) The arrival of a rig unit on location;

(2) The movement of a rig unit to another slot. For movements that will occur less than 72 hours after initially moving onto location (*e.g.,* coiled tubing and batch operations), you may include your anticipated movement schedule on Form BSEE–0144; or

(3) The departure of a rig unit from the location.

(b) You must provide the District Manager with the rig name, lease number, well number, and expected time of arrival or departure.

(c) If a MODU or platform rig is to be warm or cold stacked, you must inform the District Manager;

(1) Where the MODU or platform rig is coming from;

(2) The location of where the MODU or platform rig will be positioned;

(3) Whether the MODU or platform rig will be manned or unmanned; and

(4) If the location for stacking the MODU or platform rig changes.

(d) Prior to resuming operations after stacking, you must notify the appropriate District Manager of any construction, repairs, or modifications associated with the drilling package made to the MODU or platform rig;

(e) If a drilling rig is entering OCS waters, you must inform the District Manager where the drilling rig is coming from.

(f) If you change your anticipated date for initially moving on or off location by more than 24 hours, you must submit an updated Form BSEE–0144, Rig Movement Notification Report.

§ 250.713 What must I provide if I plan to use a mobile offshore drilling unit (MODU) or lift boat for well operations?

If you plan to use a MODU or lift boat for well operations, you must provide:

(a) *Fitness requirements.* Information and data to demonstrate the capability to perform at the proposed location. This information must include the most extreme environmental and operational conditions that the unit is designed to withstand, including the minimum air gap necessary for both hurricane and non-hurricane seasons. If sufficient environmental information and data are not available at the time you submit your APD or APM, the District Manager may approve your APD or APM, but require you to collect and report this information during operations. Under this circumstance, the District Manager has the right to revoke the approval of the APD or APM if information collected during operations shows that the MODU or lift boat is not capable of performing at the proposed location.

(b) *Foundation requirements.* Information to show that site-specific soil and oceanographic conditions are capable of supporting the proposed MODU or lift boat. If you provided sufficient site-specific information in your EP, DPP, or DOCD submitted to BOEM, you may reference that information. The District Manager may require you to conduct additional surveys and soil borings before approving the APD or APM if additional information is needed to make a determination that the conditions are capable of supporting the MODU, lift boat, or equipment installed on a subsea wellhead. For moored rigs, you must submit a plat of the rigs' anchor pattern approved in your EP, DPP, or DOCD in your APD or APM.

(c) *For frontier areas.* (1) If the design of the MODU or lift boat you plan to use in a frontier area is unique or has not been proven for use in the proposed environment, the District Manager may require you to submit a third-party review of the MODU or lift boat design. If required, you must obtain a third-party review of your MODU or lift boat similar to the process outlined in §§ 250.915 through 250.918. You may submit this information before submitting an APD or APM.

(2) If you plan to conduct operations in a frontier area, you must have a contingency plan that addresses design and operating limitations of the MODU or lift boat. Your plan must identify the actions necessary to maintain safety and prevent damage to the environment. Actions must include the suspension, curtailment, or modification of operations to remedy various operational or environmental situations (*e.g.,* vessel motion, riser offset, anchor tensions, wind speed, wave height, currents, icing or ice-loading, settling, tilt or lateral movement, resupply capability).

(d) *Additional documentation.* You must provide the current Certificate of Inspection (for US Flagged vessels) or Certificate of Compliance (for Foreign Flagged vessels) from the USCG and Certificate of Classification. You must also provide current documentation of any operational limitations imposed by an appropriate classification society.

(e) *Dynamically positioned rig unit.* If you use a dynamically positioned MODU, you must include in your APD or APM your contingency plan for moving off location in an emergency situation. Your plan must include, but not be limited to, such emergency events caused by storms, currents, station-keeping failure, power failure, and loss of well control. The District Manager may require your plan to include additional events and information.

(f) *Inspection of unit.* The MODU or lift boat must be available for inspection by the District Manager before commencing operations and at any time during operations.

(g) *Current Monitoring.* For water depths greater than 400 meters (1,312 feet), you must include in your APD or APM:

(1) A description of the specific current speeds that will cause you to implement rig shutdown, move-off procedures, or both; and

(2) A discussion of the specific measures you will take to curtail rig operations and move off location when such currents are encountered. You may use criteria such as current velocities, riser angles, watch circles, and remaining rig power to describe when these procedures or measures will be implemented.

§ 250.714 Do I have to develop a dropped objects plan?

If you use a floating rig unit in an area with subsea infrastructure, you must develop a dropped objects plan and make it available to BSEE upon request. This plan must be updated as the infrastructure on the seafloor changes. Your plan must include:

(a) A description and plot of the path the rig will take while running and pulling the riser;

(b) A plat showing the location of any subsea wells, production equipment, pipelines, and any other identified debris;

(c) Modeling of a dropped object's path with consideration given to metocean conditions for various material forms, such as a tubular (*e.g.,* riser or casing) and box (*e.g.,* BOP or tree);

(d) Communications, procedures, and delegated authorities established with the production host facility to shut-in any active subsea wells, equipment, or pipelines in the event of a dropped object; and

(e) Any additional information required by the District Manager.

§ 250.715 Do I need a global positioning system (GPS) for MODUs and jack-ups?

All jack-up and moored MODUs must have a minimum of two functioning GPS transponders at all times, and you must provide to BSEE real-time access to the GPS data prior to each hurricane season.

(a) The GPS must be capable of monitoring the position and tracking the path in real-time if the moored MODU or jack-up moves from its location during a severe storm.

(b) You must install and protect the tracking system's equipment to minimize the risk of the system being disabled.

(c) You must place the GPS transponders in different locations for redundancy to minimize risk of system failure.

(d) Each GPS transponder must be capable of transmitting data for at least 7 days after a storm has passed.

(e) If the MODU is moved off location in the event of a storm, you must immediately begin to record the GPS location data.

(f) Contact the Regional Office and allow real-time access to the MODU or jack-up location data. When you contact the Regional Office, provide the following:

(1) Name of the lessee and operator with contact information;

(2) Rig/facility/platform name;

(3) Initial date and time; and

(4) How you will provide GPS real-time access.

Well Operations

§ 250.720 When and how must I secure a well?

(a) Whenever you interrupt operations, you must notify the District Manager. Before moving off the well, you must have two independent barriers installed, at least one of which must be a mechanical barrier, as approved by the District Manager. You must install the barriers at appropriate depths within a properly cemented casing string or liner. Before removing a subsea BOP stack or surface BOP stack on a mudline suspension well, you must conduct a negative pressure test in accordance with § 250.721.

(1) The events that would cause you to interrupt operations and notify the District Manager include, but are not limited to, the following:

(i) Evacuation of the rig crew;

(ii) Inability to keep the rig on location;

(iii) Repair to major rig or well-control equipment; or

(iv) Observed flow outside the well's casing (*e.g.,* shallow water flow or bubbling).

(2) The District Manager may approve alternate procedures or barriers in accordance with § 250.141 if you do not have time to install the required barriers or if special circumstances occur.

(b) Before you displace kill-weight fluid from the wellbore and/or riser, thereby creating an underbalanced state, you must obtain approval from the BSEE District Manager. To obtain approval, you must submit with your APD or APM your reasons for displacing the kill-weight fluid and provide detailed step-by-step written procedures describing how you will safely displace these fluids. The step-by-step displacement procedures must address the following:

(1) Number and type of independent barriers, as described in § 250.420(b)(3), that are in place for each flow path that requires such barriers,

(2) Tests you will conduct to ensure integrity of independent barriers,

(3) BOP procedures you will use while displacing kill-weight fluids, and

(4) Procedures you will use to monitor the volumes and rates of fluids entering and leaving the wellbore.

§ 250.721 What are the requirements for pressure testing casing and liners?

(a) You must test each casing string that extends to the wellhead according to the following table:

Casing type	Minimum test pressure
(1) Drive or Structural,	Not required.
(2) Conductor, excluding subsea wellheads.	250 psi.
(3) Surface, Intermediate, and Production,	70 percent of its minimum internal yield.

(b) You must test each drilling liner and liner-lap to a pressure at least equal to the anticipated leak off pressure of the formation below that liner shoe, or subsequent liner shoes if set. You must conduct this test before you continue operations in the well.

(c) You must test each production liner and liner-lap to a minimum of 500 psi above the formation fracture pressure at the casing shoe into which the liner is lapped.

(d) The District Manager may approve or require other casing test pressures.

(e) If you plan to produce a well, you must:

(1) For a well that is fully cased and cemented, pressure test the entire well to maximum anticipated shut-in tubing pressure before perforating the casing or liner; or

(2) For an open-hole completion, pressure test the entire well to maximum anticipated shut-in tubing pressure before you drill the open-hole section.

(f) You may not resume operations until you obtain a satisfactory pressure test. If the pressure declines more than 10 percent in a 30-minute test, or if there is another indication of a leak, you must submit to the District Manager for approval your proposed plans to re-cement, repair the casing or liner, or run additional casing/liner to provide a proper seal. Your submittal must include a PE certification of your proposed plans.

(g) You must perform a negative pressure test on all wells that use a subsea BOP stack or wells with mudline suspension systems.

(1) You must perform a negative pressure test on your final casing string or liner. This test must be conducted after setting your second barrier just above the shoe track, but prior to conducting any completion operations.

(2) You must perform a negative test prior to unlatching the BOP at any point in the well. The negative test must be performed on those components, at a minimum, that will be exposed to the negative differential pressure that will occur when the BOP is disconnected.

(3) The District Manager may require you to perform additional negative pressure tests on other casing strings or liners (*e.g.,* intermediate casing string or liner) or on wells with a surface BOP stack.

(4) You must submit for approval with your APD or APM, test procedures and criteria for a successful negative test. If any of your test procedures or criteria for a successful test change, you must submit for approval the changes in a revised APD or APM.

(5) You must document all your test results and make them available to BSEE upon request.

(6) If you have any indication of a failed negative pressure test, such as, but not limited to, pressure buildup or observed flow, you must immediately investigate the cause. If your investigation confirms that a failure occurred during the negative pressure test, you must:

(i) Correct the problem and immediately notify the appropriate BSEE District Manager; and

(ii) Submit a description of the corrective action taken and receive approval from the appropriate BSEE District Manager for the retest.

(7) You must have two barriers in place, as described in § 250.420(b)(3), at any time and for any well, prior to performing the negative pressure test.

(8) You must include documentation of the successful negative pressure test in the End-of-Operations Report (Form BSEE–0125).

§ 250.722 What are the requirements for prolonged operations in a well?

If wellbore operations continue within a casing or liner for more than 30 days from the previous pressure test of the well's casing or liner, you must:

(a) Stop operations as soon as practicable, and evaluate the effects of the prolonged operations on continued operations and the life of the well. At a minimum, you must:

(1) Evaluate the well's casing with either a pressure test, caliper tool, or imaging tool. On a case-by-case basis the District Manager may require a specific method of evaluation; and

(2) Report the results of your evaluation to the District Manager and obtain approval of those results before resuming operations. Your report must include calculations that show the well's integrity is above the minimum safety factors.

(b) If well integrity has deteriorated to a level below minimum safety factors, you must:

(1) Obtain approval from the District Manager to begin repairs or install additional casing. To obtain approval, you must also provide a PE certification showing that he or she reviewed and approved the proposed changes;

(2) Repair the casing or run another casing string; and

(3) Perform a pressure test after the repairs are made or additional casing is installed and report the results to the District Manager as specified in § 250.721.

§ 250.723 What additional safety measures must I take when I conduct operations on a platform that has producing wells or has other hydrocarbon flow?

You must take the following safety measures when you conduct operations with a rig unit or lift boat on or jacked-up over a platform with producing wells or that has other hydrocarbon flow:

(a) The movement of rig units and related equipment on and off a platform or from well to well on the same platform, including rigging up and rigging down, must be conducted in a safe manner;

(b) You must install an emergency shutdown station for the production system near the rig operator's console;

(c) You must shut-in all producible wells located in the affected wellbay below the surface and at the wellhead when:

(1) You move a rig unit or related equipment on and off a platform. This includes rigging up and rigging down activities within 500 feet of the affected platform;

(2) You move or skid a rig unit between wells on a platform; or

(3) A MODU or lift boat moves within 500 feet of a platform. You may resume production once the MODU or lift boat is in place, secured, and ready to begin operations.

(d) All wells in the same well-bay which are capable of producing hydrocarbons must be shut-in below the surface with a pump-through-type tubing plug and at the surface with a closed master valve prior to moving rig units and related equipment unless otherwise approved by the District Manager.

(1) A closed surface-controlled subsurface safety valve of the pump-through-type may be used in lieu of the pump-through-type tubing plug provided that the surface control has been locked out of operation.

(2) The well to which a rig unit or related equipment is to be moved must be equipped with a back-pressure valve prior to removing the tree and installing and testing the BOP system.

(3) The well from which a rig unit or related equipment is to be moved must be equipped with a back pressure valve prior to removing the BOP system and installing the production tree.

(e) Coiled tubing units, snubbing units, or wireline units may be moved onto and off of a platform without shutting in wells.

§ 250.724 What are the real-time monitoring requirements?

(a) When conducting well operations with a subsea BOP or surface BOP on a floating facility or when operating in an HPHT environment you must, within 3 years of publication of the final rule, gather and monitor real-time well data using an independent, automatic, and continuous monitoring system capable of recording, storing, and transmitting all aspects of:

(1) The BOP control system;

(2) The well's fluid handling systems on the rig; and

(3) The well's downhole conditions with the bottom hole assembly tools (if any tools are installed).

(b) You must immediately transmit these data as they are gathered to a designated onshore location during operations where they must be monitored by qualified personnel who must be in continuous contact with rig personnel during operations. After operations, you must preserve and store this data at a designated location for recordkeeping purposes as required in §§ 250.740 and 250.741. You must designate the location where the data will be stored and monitored during operations in your APD or APM. The location and the data must be made accessible to BSEE upon request.

(c) If you lose any real-time monitoring capability during operations covered by this section, you must immediately notify the District Manager. The District Manager may require other measures until real-time monitoring capability is restored.

Blowout Preventer (BOP) System Requirements

§ 250.730 What are the general requirements for BOP systems and system components?

(a) You must design, install, maintain, inspect, test, and use the BOP system and system components to ensure well control. The working-pressure rating of each BOP component must exceed MASP as defined for the operation. For a subsea BOP, the MASP must be taken at the mudline. The BOP system includes the BOP stack, control system, and any other associated system(s) and equipment. The BOP system and individual components must be able to perform their expected functions and be compatible with each other. Each ram (excluding casing shear/supershear) must be capable of closing and sealing the wellbore at all times, including under flowing conditions as defined for the operation and specific well conditions, without losing ram closure time and sealing integrity due to the corrosiveness, volume, and abrasiveness of any fluids in the wellbore that you may encounter. Your BOP system must meet the following requirements:

(1) The BOP requirements of API Standard 53 (incorporated by reference in § 250.198) and the requirements of §§ 250.733 through 250.739. If there is a conflict between API Standard 53 and the requirements of this subpart, you must follow the requirements of this subpart.

(2) The following industry standards (all incorporated by reference in § 250.198):

(i) ANSI/API Spec. 6A;
(ii) ANSI/API Spec. 16A;
(iii) ANSI/API Spec. 16C;
(iv) API Spec. 16D; and
(v) ANSI/API Spec. 17D.

(3) For surface and subsea BOPs, the pipe and variable bore rams installed in the BOP stack must be capable of effectively closing and sealing on the tubular body of any drill pipe, workstring, and tubing in the hole under MASP, as defined for the operation, with the proposed regulator settings of the BOP control system.

(4) The current set of approved schematic drawings must be available on the rig and at an onshore location. If you make any modifications to the BOP or control system that will change your BSEE-approved schematic drawings, you must suspend operations until you obtain approval from the District Manager.

(b) You must design, fabricate, maintain, and repair your BOP system according to the requirements contained in this subpart, OEM recommendations unless otherwise directed by BSEE, and recognized engineering practices. The training and qualification of repair and maintenance personnel must meet or exceed any OEM training recommendations unless otherwise directed by BSEE.

(c) You must follow the failure reporting procedures contained in API Standard 53, ANSI/API Spec. 6A, and ANSI/API Spec 16A, and:

(1) You must provide a written report of equipment failure to the manufacturer of such equipment within 30 days after the discovery and identification of the failure.

(2) You must ensure that an investigation and a failure analysis are initiated within 60 days of the failure to determine the cause of the failure. If the investigation and analysis are performed by an entity other than the manufacturer, you must ensure that the manufacturer receives a copy of the analysis.

(3) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed, or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such notice or change, report the design change or modified procedures in writing to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; HE 3314; 45600 Woodland Road, Sterling, Virginia 20166.

(d) If you plan to use a BOP stack manufactured after the effective date of this regulation, you must use one manufactured pursuant to an API Spec. Q1 (as incorporated by reference in § 250.198) quality management system. Such quality management system must be certified by an entity that meets the requirements of ISO 17011.

(1) The BSEE may consider accepting equipment manufactured under quality assurance programs other than API Spec. Q1, provided you submit a request to BSEE containing relevant information about the alternative program and receive BSEE approval under § 250.141.

(2) You must submit this request to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; HE 3314: 45600 Woodland Road, Sterling, Virginia 20166.

§ 250.731 What information must I submit for BOP systems and system components?

For any operation that requires the use of a BOP, you must include the information listed in this section with your applicable APD, APM, or other submittal. You are required to submit this information only once for each well, unless the information changes from what you provided in an earlier approved submission or you have moved off location from the well. After you have submitted this information for a particular well, subsequent APMs or other submittals for the well should reference the approved submittal containing the information required by this section and confirm that the information remains accurate and that you have not moved off location from that well. If the information changes or you have moved off location from the well, you must submit updated information in your next submission.

You must submit:	Including:
(a) A complete description of the BOP system and system components,	(1) Pressure ratings of BOP equipment;
	(2) Proposed BOP test pressures (for subsea BOPs, include both surface and corresponding subsea pressures);
	(3) Rated capacities for liquid and gas for the fluid-gas separator system;
	(4) Control fluid volumes needed to close, seal, and open each component;

You must submit:	Including:
	(5) Control system pressure and regulator settings needed to achieve an effective seal of each ram BOP under MASP as defined for the operation; (6) Number and volume of accumulator bottles and bottle banks (for subsea BOP, include both surface and subsea bottles); (7) Accumulator pre-charge calculations (for subsea BOP, include both surface and subsea calculations); (8) All locking devices; and (9) Control fluid volume calculations for the accumulator system (for a subsea BOP system, include both the surface and subsea volumes).
(b) Schematic drawings,	(1) The inside diameter of the BOP stack, (2) Number and type of preventers (including blade type for shear ram(s)), (3) All locking devices, (4) Size range for variable bore ram(s), (5) Size of fixed ram(s), (6) All control systems with all alarms and set points labeled, including pods, (7) Location and size of choke and kill lines (and gas bleed line(s) for subsea BOP), (8) Associated valves of the BOP system, (9) Control station locations, and (10) A cross-section of the riser for a subsea BOP system showing number, size, and labeling of all control, supply, choke, and kill lines down to the BOP.
(c) Certification by a BSEE-approved verification organization,	Verification that: (1) Test data clearly demonstrates the shear ram(s) will shear the drill pipe at the water depth as required in § 250.732; (2) The BOP was designed, tested, and maintained to perform at the most extreme anticipated conditions; and (3) The accumulator system has sufficient fluid to function the BOP system without assistance from the charging system.
(d) Additional certification by a BSEE-approved verification organization, if you use a subsea BOP, a BOP in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility,	Verification that: (1) The BOP stack is designed for the specific equipment on the rig and for the specific well design; (2) The BOP stack has not been compromised or damaged from previous service; and (3) The BOP stack will operate in the conditions in which it will be used.
(e) If you are using a subsea BOP, descriptions of autoshear, deadman, and emergency disconnect sequence (EDS) systems,	A listing of the functions with their sequences and timing.
(f) Certification stating that the Mechanical Integrity Assessment Report required in § 250.732(d) has been submitted within the past 12 months for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility.	

§ 250.732 What are the BSEE-approved verification organization requirements for BOP systems and system components?

(a) The BSEE will maintain a list of BSEE-approved verification organizations that you may use. For an organization to become a BSEE approved verification organization, it must submit the following information to the Chief, Office of Regulatory Programs: Bureau of Safety and Environmental Enforcement: 45600 Woodland Road, Sterling, Virginia, 20166, for BSEE review and approval:

(1) Previous experience in verification or in the design, fabrication, installation, repair, or major modification of BOPs and related systems and equipment;

(2) Technical capabilities;

(3) Size and type of organization;

(4) In-house availability of, or access to, appropriate technology. This should include computer programs, hardware, and testing materials and equipment;

(5) Ability to perform the verification functions for projects considering current commitments;

(6) Previous experience with BSEE requirements and procedures; and

(7) Any additional information that may be relevant to BSEE's review.

(b) Prior to beginning any operation requiring the use of any BOP, you must submit verification by a BSEE-approved verification organization and supporting documentation as required by this paragraph to the appropriate District Manager and Regional Supervisor.

You must submit verification and documentation related to:	That:
(1) Shear testing,	(i) Demonstrates that the BOP will shear the drill pipe and any electric-, wire-, and slick-line to be used in the well;

You must submit verification and documentation related to:	That:
	(ii) Demonstrates the use of test protocols and analysis that represent recognized engineering practices for ensuring the repeatability and reproducibility of the tests, and that the testing was performed by a facility that meets generally accepted quality assurance standards; (iii) Provides a reasonable representation of field applications, taking into consideration the physical and mechanical properties of the drill pipe; (iv) Ensures testing was performed on the outermost edges of the shearing blades of the positioning mechanism as required in § 250.734(a)(16); (v) Demonstrates the shearing capacity of the BOP equipment to the physical and mechanical properties of the drill pipe; and (vi) Includes all testing results.
(2) Pressure integrity testing, and	(i) Shows that testing is conducted immediately after the shearing tests; (ii) Demonstrates that the equipment will seal at the rated working pressure of the BOP for 30 minutes; and (iii) Includes all test results.
(3) Calculations.	Include shearing and sealing pressures for all pipe to be used in the well including corrections for MASP.

(c) For wells in an HPHT environment, as defined by § 250.807(b), you must submit verification by a BSEE-approved verification organization that the verification organization conducted a comprehensive review of the BOP system and related equipment you propose to use. You must provide the BSEE-approved verification organization access to any facility associated with the BOP system or related equipment during the review process. You must submit the verifications required by this paragraph to the appropriate District Manager and Regional Supervisor before you begin any operations in an HPHT environment with the proposed equipment.

You must submit:	Including:
(1) Verification that the verification organization conducted a detailed review of the design package to ensure that all critical components and systems meet recognized engineering practices,	
(2) Verification that the designs of individual components and the overall system have been proven in a testing process that demonstrates the performance and reliability of the equipment in a manner that is repeatable and reproducible,	(i) Identification of all reasonable potential modes of failure, and (ii) Evaluation of the design verification tests. The design verification tests must assess the equipment for the identified potential modes of failure.
(3) Verification that the BOP equipment will perform as designed in the temperature, pressure, and environment that will be encountered, and	
(4) Verification that the fabrication, manufacture, and assembly of individual components and the overall system uses recognized engineering practices and quality control and assurance mechanisms.	For the quality control and assurance mechanisms, complete material and quality controls over all contractors, subcontractors, distributors, and suppliers at every stage in the fabrication, manufacture, and assembly process.

(d) Once every 12 months, you must submit a Mechanical Integrity Assessment Report for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility. This report must be completed by a BSEE-approved verification organization. You must submit this report to the Chief, Office of Regulatory Programs: Bureau of Safety and Environmental Enforcement: 45600 Woodland Road, Sterling, Virginia, 20166. This report must include:

(1) A determination that the BOP stack and system meets or exceeds all BSEE regulatory requirements, industry standards incorporated into this subpart, and recognized engineering practices.

(2) Verification that complete documentation of the equipment's service life exists that demonstrates that the BOP stack has not been compromised or damaged during previous service.

(3) A description of all inspection, repair and maintenance records reviewed, and verification that all repairs, replacement parts, and maintenance meet regulatory requirements, recognized engineering practices, and OEM specifications.

(4) A description of records reviewed related to any modifications to the equipment and verification that any such changes do not adversely affect the equipment's capability to perform as designed or invalidate test results.

(5) A description of the Safety and Environmental Management Systems (SEMS) plans reviewed related to assurance of quality and mechanical integrity of critical equipment and verification that the plans are comprehensive and fully implemented.

(6) Verification that the qualification and training of inspection, repair, and maintenance personnel for the BOP systems meet recognized engineering practices and OEM requirements.

(7) A description of all records reviewed covering OEM safety alerts, all failure reports, and verification that any design or maintenance issues have been completely identified and corrected.

(8) A comprehensive assessment of the overall system and verification that all components (including mechanical, hydraulic, electrical, and software) are compatible.

(9) Verification that documentation exists concerning the traceability of the fabrication, repair, and maintenance of all critical components.

(10) Verification of use of a formal maintenance tracking system to ensure that corrective maintenance and scheduled maintenance is implemented in a timely manner.

(11) Identification of gaps or deficiencies related to inspection and maintenance procedures and documentation, documentation of any deferred maintenance, and verification of the completion of corrective action plans.

(12) Verification that any inspection, maintenance, or repair work meets the manufacturer's design and material specifications.

(13) Verification of written procedures for operating the BOP stack and LMRP (including proper techniques to prevent accidental disconnection of these components) and minimum knowledge requirements for personnel authorized to operate and maintain BOP components.

(14) Recommendations, if any, for how to improve the fabrication, installation, operation, maintenance, inspection, and repair of the equipment.

(e) You must make all documentation that supports the requirements of this section available to BSEE upon request.

§ 250.733 What are the requirements for a surface BOP stack?

(a) When you drill or conduct operations with a surface BOP stack, you must install the BOP system before drilling or conducting operations to deepen the well below the surface casing and after the well is deepened below the surface casing point. The surface BOP stack must include at least four remote-controlled, hydraulically operated BOPs, consisting of one annular BOP, one BOP equipped with blind-shear rams, and two BOPs equipped with pipe rams.

(1) The blind-shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that include heavy-weight pipe or collars), workstring, tubing, and any electric-, wire-, and slick-line that is in the hole and sealing the wellbore after shearing. If your blind-shear rams are unable to cut any electric-, wire-, or slick-line under MASP as defined for the operation and seal the wellbore, you must use an alternative cutting device capable of shearing the lines before closing the BOP. This device must be available on the rig floor during operations that require their use.

(2) The two BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, excluding the bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools.

(b) If you plan to use a surface BOP on a floating production facility you must:

(1) Follow the BOP requirements in § 250.734(a)(1). You must comply with this requirement within 5 years from the publication of the final rule.

(2) Use a dual bore riser configuration, for risers installed after the effective date of this rule, before drilling or operating in any hole section or interval where hydrocarbons are, or may be, exposed to the well. The dual bore riser must meet the design requirements of API RP 2RD (as incorporated by reference in § 250.198) including appropriate design for the most extreme anticipated operating and environmental conditions.

(i) For a dual bore riser configuration, the annulus between the risers must be monitored during operations. You must describe in your APD or APM your annulus monitoring plan and how you will secure the well in the event a leak is detected.

(ii) The inner riser for a dual riser configuration is subject to the requirements for testing the casing or liner at § 250.721.

(c) You must install separate side outlets on the BOP stack for the kill and choke lines. If your stack does not have side outlets, you must install a drilling spool with side outlets. The outlet valves must hold pressure from both directions.

(d) You must install a choke and a kill line on the BOP stack. You must equip each line with two full-bore, full-opening valves, one of which must be remote-controlled. On the kill line, you may install a check valve and a manual valve instead of the remote-controlled valve. To use this configuration, both manual valves must be readily accessible and you must install the check valve between the manual valves and the pump.

(e) You must install hydraulically operated locks.

(f) For a surface BOP used in HPHT environments, if operations are suspended to make repairs to any part of the BOP system, you must stop operations at a safe downhole location. Before resuming operations you must:

(1) Submit a revised APD or APM including documentation of the repairs and a certification from a BSEE-approved verification organization stating that they reviewed the repairs, and that the BOP is fit for service; and

(2) Receive approval from the District Manager.

§ 250.734 What are the requirements for a subsea BOP system?

(a) When you drill or conduct operations with a subsea BOP system, you must install the BOP system before drilling to deepen the well below the surface casing or conducting operations if the well is already deepened beyond the surface casing point. The District Manager may require you to install a subsea BOP system before drilling or conducting operations below the conductor casing if proposed casing setting depths or local geology indicate the need. The following table outlines your requirements.

When operating with a subsea BOP system, you must:	Additional requirements
(1) Have at least five remote-controlled, hydraulically operated BOPs;	You must have at least one annular BOP, two BOPs equipped with pipe rams, and two BOPs equipped with shear rams. For the two shear ram requirement, you must comply with this requirement within 5 years from the publication of the final rule. (i) Both BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, excluding the bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools.

When operating with a subsea BOP system, you must:	Additional requirements
	(ii) Both shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that includes heavy-weight pipe or collars), workstring, tubing, appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric-, wire-, slick-line in the hole under MASP. At least one shear ram must be capable of sealing the wellbore after shearing under MASP conditions as defined for the operation. Any non-sealing shear rams must be installed below the sealing shear rams.
(2) Have an operable dual-pod control system to ensure proper and independent operation of the BOP system;	
(3) Have the accumulator capacity located subsea, to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface;	The accumulator capacity must: (i) Function each required shear ram, choke and kill side outlet valves, one pipe ram, and disconnect the LMRP. (ii) Have the capability of delivering fluid to each ROV function *i.e.,* flying leads. (iii) Have dedicated independent bottles for the autoshear, deadman, and EDS systems. (iv) Perform under MASP conditions as defined for the operation.
(4) Have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention capability;	The ROV must be capable of performing critical functions, including opening and closing each shear ram, choke and kill side outlet valves, all pipe rams, and LMRP disconnect under MASP conditions as defined for the operation. The ROV panels on the BOP and LMRP must be compliant with API RP 17H (as incorporated by reference in § 250.198).
(5) Maintain an ROV and have a trained ROV crew on each rig unit on a continuous basis once BOP deployment has been initiated from the rig until recovered to the surface. The crew must examine all ROV related well-control equipment (both surface and subsea) to ensure that it is properly maintained and capable of shutting in the well during emergency operations;	The crew must be trained in the operation of the ROV. The training must include simulator training on stabbing into an ROV intervention panel on a subsea BOP stack. The ROV crew must be in communication with designated rig personnel who are knowledgeable about the BOP's capabilities.
(6) Provide autoshear, deadman, and EDS systems for dynamically positioned rigs; provide autoshear and deadman systems for moored rigs;	(i) *Autoshear system* means a safety system that is designed to automatically shut-in the wellbore in the event of a disconnect of the LMRP. This is considered a *rapid discharge* system. (ii) *Deadman system* means a safety system that is designed to automatically shut-in the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods. This is considered a *rapid discharge* system. (iii) *Emergency Disconnect Sequence (EDS) system* means a safety system that is designed to be manually activated to shut-in the wellbore and disconnect the LMRP in the event of an emergency situation. This is considered a *rapid discharge* system. (iv) Each emergency function must close at a minimum, two shear rams in sequence and be capable of performing their expected shearing and sealing action under MASP conditions as defined for the operation. (v) Your sequencing must allow a sufficient delay for closing the upper shear ram after beginning closure of the lower shear ram to provide for maximum shearing efficiency. (vi) The control system for the emergency functions must be a fail-safe design, and the logic must provide for the subsequent step to be independent from the previous step having to be completed.
(7) Demonstrate that any acoustic control system will function in the proposed environment and conditions;	If you choose to install an acoustic control system in addition to the autoshear, deadman, and EDS requirements, you must demonstrate to the District Manager, as part of the information submitted under § 250.731, that the acoustic system will function in the proposed environment and conditions. The District Manager may require additional information.
(8) Have operational or physical barrier(s) on BOP control panels to prevent accidental disconnect functions;	Incorporate enable buttons on control panels to ensure two-handed operation for all critical functions.
(9) Clearly label all control panels for the subsea BOP system;	Label other BOP control panels such as hydraulic control panel.
(10) Develop and use a management system for operating the BOP system, including the prevention of accidental or unplanned disconnects of the system;	The management system must include written procedures for operating the BOP stack and LMRP (including proper techniques to prevent accidental disconnection of these components) and minimum knowledge requirements for personnel authorized to operate and maintain BOP components.
(11) Establish minimum requirements for personnel authorized to operate critical BOP equipment;	Personnel must have: (i) Training in deepwater well-control theory and practice according to the requirements of Subpart O; and (ii) A comprehensive knowledge of BOP hardware and control systems.

When operating with a subsea BOP system, you must:	Additional requirements
(12) Before removing the marine riser, displace the fluid in the riser with seawater;	You must maintain sufficient hydrostatic pressure or take other suitable precautions to compensate for the reduction in pressure and to maintain a safe and controlled well condition. You must follow the requirements of § 250.720(b).
(13) Install the BOP stack in a well cellar when in an ice-scour area;	Your well cellar must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.
(14) Install at least two side outlets for a choke line and two side outlets for a kill line;	(i) If your stack does not have side outlets, you must install a drilling spool with side outlets. (ii) Each side outlet must have two full-bore, full-opening valves. (iii) The valves must hold pressure from both directions and must be remote-controlled. (iv) You must install a side outlet below each sealing shear ram. You may have a pipe ram or rams between the shearing ram and side outlet.
(15) Install a gas bleed line with two valves for the annular preventer; ..	(i) The valves must hold pressure from both directions; (ii) If you have dual annulars, where one annular is on the LMRP and one annular is on the lower BOP stack, you must install a gas bleed line on each annular.
(16) Use a BOP system that has the following mechanisms and capabilities:	(i) A mechanism coupled with each shear ram to position the entire pipe, including connection, completely within the area of the shearing blade and ensure shearing will occur any time the shear rams are activated. This mechanism cannot be another ram BOP or annular preventer, but you may use those during a planned shear. You must install this mechanism within 7 years from the publication of the final rule; (ii) The ability to mitigate compression of the pipe stub between the shearing rams when both shear rams are closed; (iii) If your control pods contain a subsea electronic module with batteries, a mechanism for personnel on the rig to monitor the state of charge of the subsea electronic module batteries in the BOP control pods.

(b) If operations are suspended to make repairs to any part of the subsea BOP system, you must stop operations at a safe downhole location. Before resuming operations you must:

(1) Submit a revised permit with a verification report from a BSEE-approved verification organization documenting the repairs and that the BOP is fit for service;

(2) Perform a new BOP test in accordance with §§ 250.737 and 250.738 upon relatch including deadman and ROV intervention; and

(3) Receive approval from the District Manager.

(c) If you plan to drill a new well with a subsea BOP, you do not need to submit with your APD the verifications required by this subpart for the open water drilling operation. Before drilling out the surface casing, you must submit for approval a revised APD, including the verifications required in this subpart.

§ 250.735 What associated systems and related equipment must all BOP systems include?

All BOP systems must include the following associated systems and related equipment:

(a) A surface accumulator system that provides 1.5 times the volume of fluid capacity necessary to close and hold closed all BOP components against MASP. The system must operate under MASP conditions as defined for the operation. You must be able to operate all BOP functions without assistance from a charging system, with the blind shear ram being the last in the sequence, and still have enough pressure to shear pipe and seal the well with a minimum pressure of 200 psi remaining on the bottles above the precharge pressure. If you supply the accumulator regulators by rig air and do not have a secondary source of pneumatic supply, you must equip the regulators with manual overrides or other devices to ensure capability of hydraulic operations if rig air is lost;

(b) An automatic backup to the primary accumulator-charging system. The power source must be independent from the power source for the primary accumulator-charging system. The independent power source must possess sufficient capability to close and hold closed all BOP components under MASP conditions as defined for the operation;

(c) At least two full BOP control stations. One station must be on the rig floor. You must locate the other station in a readily accessible location away from the rig floor;

(d) The choke line(s) installed above the bottom well-control ram;

(e) The kill line that may be installed below the bottom ram, but it must be installed beneath at least one pipe ram;

(f) A fill-up line above the uppermost BOP;

(g) Hydraulically operated locking devices installed on the sealing ram-type BOPs; and

(h) A wellhead assembly with a rated working pressure that exceeds the maximum anticipated wellhead pressure.

§ 250.736 What are the requirements for choke manifolds, kelly valves, inside BOPs, and drill string safety valves?

(a) Your BOP system must include a choke manifold that is suitable for the anticipated surface pressures, anticipated methods of well control, the surrounding environment, and the corrosiveness, volume, and abrasiveness of drilling fluids and well fluids that you may encounter.

(b) Choke manifold components must have a rated working pressure at least as great as the rated working pressure of the ram BOPs. If your choke manifold has buffer tanks downstream of choke assemblies, you must install isolation valves on any bleed lines.

(c) Valves, pipes, flexible steel hoses, and other fittings upstream of the choke manifold must have a rated working pressure at least as great as the rated working pressure of the ram BOPs.

(d) You must use the following BOP equipment with a rated working pressure and temperature of at least as great as the working pressure and temperature of the ram BOP during all operations:

(1) A kelly valve installed below the swivel (upper kelly valve);

(2) A kelly valve installed at the bottom of the kelly (lower kelly valve). You must be able to strip the lower kelly valve through the BOP stack;

(3) If you operate with a mud motor and use drill pipe instead of a kelly, one kelly valve installed above, and one strippable kelly valve installed below, the joint of pipe used in place of a kelly;

(4) On a top-drive system equipped with a remote-controlled valve, a strippable kelly-type valve installed below the remote-controlled valve;

(5) An inside BOP in the open position located on the rig floor. You must be able to install an inside BOP for each size connection in the pipe;

(6) A drill string safety valve in the open position located on the rig floor. You must have a drill-string safety valve available for each size connection in the pipe;

(7) When running casing, a safety valve in the open position available on the rig floor to fit the casing string being run in the hole;

(8) All required manual and remote-controlled kelly valves, drill-string safety valves, and comparable-type valves (*i.e.,* kelly-type valve in a top-drive system) that are essentially full opening; and

(9) A wrench to fit each manual valve. Each wrench must be readily accessible to the drilling crew.

§ 250.737 What are the BOP system testing requirements?

Your BOP system (this includes the choke manifold, kelly valves, inside BOP, and drill string safety valve) must meet the following testing requirements:

(a) *Pressure test frequency.* You must pressure test your BOP system:

(1) When installed;

(2) Before 14 days have elapsed since your last BOP pressure test, or 30 days since your last blind-shear ram BOP pressure test. You must begin to test your BOP system before midnight on the 14th day (or 30th day for your blind-shear rams) following the conclusion of the previous test;

(3) Before drilling out each string of casing or a liner. You may omit this pressure test requirement if you did not remove the BOP stack to run the casing string or liner, the required BOP test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test, and the time elapsed between tests has not exceeded 14 days (or 30 days for blind-shear rams). You must indicate in your APD which casing strings and liners meet these criteria;

(4) The District Manager may require more frequent testing if conditions or your BOP performance warrants.

(b) *Pressure test procedures.* When you pressure test the BOP system, you must conduct a low-pressure test and a high-pressure test for each BOP component. You must begin each test by conducting the low-pressure test then transition to the high-pressure test. Each individual pressure test must hold pressure long enough to demonstrate the tested component(s) holds the required pressure. The table in this paragraph outlines your pressure test requirements.

You must conduct a . . .	According to the following procedures . . .
(1) Low-pressure test	All low-pressure tests must be between 250 and 350 psi. Any initial pressure above 350 psi must be bled back to a pressure between 250 and 350 psi before starting the test. If the initial pressure exceeds 500 psi, you must bleed back to zero and reinitiate the test.
(2) High-pressure test for blind-shear ram-type BOPs, ram-type BOPs, the choke manifold, outside of all choke and kill side outlet valves (and annular gas bleed valves for subsea BOP), inside of all choke and kill side outlet valves below uppermost ram, and other BOP components.	The high-pressure test must equal the rated working pressure of the equipment or be 500 psi greater than your calculated MASP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP plus 500 psi, the District Manager must have approved those test pressures in your APD.
(3) High-pressure test for annular-type BOPs, inside of choke or kill valves (and annular gas bleed valves for subsea BOP) above the uppermost ram BOP.	The high pressure test must equal 70 percent of the rated working pressure of the equipment or be 500 psi greater than your calculated MASP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP plus 500 psi, the District Manager must have approved those test pressures in your APD.

(c) *Duration of pressure test.* Each test must hold the required pressure for 5 minutes, which must be recorded on a chart not exceeding 4 hours. However, for surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable if recorded on a chart not exceeding 4 hours, or on a digital recorder. The recorded test pressures must be within the middle half of the chart range, *i.e.,* cannot be within the lower or upper one-fourth of the chart range. If the equipment does not hold the required pressure during a test, you must correct the problem and retest the affected component(s).

(d) *Additional test requirements.* You must meet the following additional BOP testing requirements:

You must . . .	Additional requirements . . .
(1) Follow the testing requirements of API Standard 53 (as incorporated in § 250.198).	If there is a conflict between API Standard 53 testing requirements and this section, you must follow the requirements of this section.
(2) Use water to test a surface BOP system.	(i) You must submit test procedures with your APD or APM for District Manager approval.
	(ii) Contact the District Manager at least 72 hours prior to beginning the test to allow BSEE representative(s) to witness testing. If BSEE representative(s) are unable to witness testing, you must provide the test results to the appropriate District Manager within 72 hours after completion of the tests.
(3) Stump test a subsea BOP system before installation.	(i) You must use water to conduct this test. You may use drilling fluids to conduct subsequent tests of a subsea BOP system.

You must . . .	Additional requirements . . .
	(ii) You must submit test procedures with your APD or APM for District Manager approval. (iii) Contact the District Manager at least 72 hours prior to beginning the stump test to allow BSEE representative(s) to witness testing. If BSEE representative(s) are unable to witness testing, you must provide the test results to the appropriate District Manager within 72 hours after completion of the tests. (iv) You must test and verify closure of all ROV intervention functions on your subsea BOP stack during the stump test. (v) You must follow (b) and (c) of this section.
(4) Perform an initial subsea BOP test.	(i) You must perform the initial subsea BOP test on the seafloor within 30 days of the stump test. (ii) You must submit test procedures with your APD or APM for District Manager approval. (iii) You must pressure test well-control rams according to (b) and (c) of this section. (iv) You must notify the District Manager at least 72 hours prior to beginning the initial subsea test for the BOP system to allow BSEE representative(s) to witness testing. (v) You must test and verify closure of at least one set of rams during the initial subsea test through a ROV hot stab. You must pressure test the selected rams according to (b) and (c) of this section.
(5) Alternate tests between control stations and pods.	(i) For two complete BOP control stations: (A) Designate a primary and secondary station, and both stations must be function-tested weekly, (B) The control station used for the pressure test must be alternated between pressure tests, and (C) For a subsea BOP, the pods must be rotated between control stations during weekly function testing, and the pod used for pressure testing must be alternated between pressure tests. (ii) Any additional control stations must be function tested every 14 days.
(6) Pressure test variable bore-pipe ram BOPs against the largest and smallest sizes of pipe in use, excluding the bottom hole assembly that includes heavy-weight pipe or collars and bottom-hole tools.	
(7) Pressure test annular type BOPs against the smallest pipe in use.	
(8) Pressure test affected BOP components following the disconnection or repair of any well-pressure containment seal in the wellhead or BOP stack assembly.	
(9) Function test annular and pipe/variable bore ram BOPs every 7 days between pressure tests.	
(10) Function test blind-shear ram BOPs every 14 days.	
(11) Actuate safety valves assembled with proper casing connections before running casing.	
(12) Test and verify closure capability of all ROV intervention functions on your subsea BOP.	(i) Each ROV must be fully compatible with the BOP stack ROV intervention panels. (ii) You must submit test procedures, including how you will test each ROV intervention function, with your APD or APM for District Manager approval. (iii) You must document all your test results and make them available to BSEE upon request.
(13) Function test autoshear, deadman, and EDS systems separately on your subsea BOP stack during the stump test. The District Manager may require additional testing of the emergency systems. You must also test the deadman system and verify closure of the shearing rams during the initial test on the seafloor.	(i) You must submit test procedures with your APD or APM for District Manager approval. The procedures for these function tests must include the schematics of the actual controls and circuitry of the system that will be used during an actual autoshear or deadman event. (ii) The procedures must also include the actions and sequence of events that take place on the approved schematics of the BOP control system and describe specifically how the ROV will be utilized during this operation. (iii) When you conduct the initial deadman system test on the seafloor, you must ensure the well is secure and, if hydrocarbons have been present, appropriate barriers are in place to isolate hydrocarbons from the wellhead. You must also have an ROV on bottom during the test. (iv) The testing of the deadman system on the seafloor must indicate the discharge pressure of the subsea accumulator system throughout the test. (v) For the function test of the deadman system during the initial test on the seafloor, you must have the ability to quickly disconnect the LMRP should the rig experience a loss of station-keeping event. You must include your quick-disconnect procedures with your deadman test procedures.

You must . . .	Additional requirements . . .
	(vi) You must pressure test the blind-shear ram(s) according to (b) and (c) of this section. (vii) If a casing shear ram is installed, you must describe how you will verify closure of the ram. (viii) You must document all your test results and make them available to BSEE upon request.

(e) Prior to conducting any shear ram tests in which you will shear pipe, you must notify the BSEE District Manager at least 72 hours in advance, to ensure that a representative of BSEE will have access to the location to witness any testing.

§ 250.738 What must I do in certain situations involving BOP equipment or systems?

The table in this section describes actions that you must take when certain situations occur with BOP systems.

If you encounter the following situation:	Then you must . . .
(a) BOP equipment does not hold the required pressure during a test;	Correct the problem and retest the affected equipment. You must report any problems or irregularities, including any leaks, to the District Manager and on the daily report as required in § 250.746.
(b) Need to repair, replace, or reconfigure a surface or subsea BOP system;	(1) First place the well in a safe, controlled condition as approved by the District Manager (*e.g.,* before drilling out a casing shoe or after setting a cement plug, bridge plug, or a packer). (2) Any repair or replacement parts must be manufactured under a quality assurance program and must meet or exceed the performance of the original part produced by the OEM. (3) You must receive approval from the District Manager prior to resuming operations with the new, repaired, or reconfigured BOP. You must submit a report from a BSEE-approved verification organization to the District Manager certifying that the BOP is fit for service.
(c) Need to postpone a BOP test due to well-control problems such as lost circulation, formation fluid influx, or stuck pipe;.	Record the reason for postponing the test in the daily report and conduct the required BOP test on the first trip out of the hole.
(d) BOP control station or pod that does not function properly;	Suspend operations until that station or pod is operable. You must report any problems or irregularities, including any leaks, to the District Manager.
(e) Plan to operate with a tapered string;	Install two or more sets of conventional or variable-bore pipe rams in the BOP stack to provide for the following: two sets of rams must be capable of sealing around the larger-size drill string and two sets of pipe rams must be capable of sealing around the smaller size pipe, excluding the bottom hole assembly that includes heavy weight pipe or collars and bottom-hole tools.
(f) Plan to install casing rams or casing shear rams in a surface BOP stack;.	Test the ram bonnets before running casing to the rated working pressure or MASP plus 500 psi. The BOP must also provide for sealing the well after casing is sheared. If this installation was not included in your approved permit, and changes the BOP configuration approved in the APD or APM, you must notify and receive approval from the District Manager.
(g) Plan to use an annular BOP with a rated working pressure less than the anticipated surface pressure;.	Demonstrate that your well-control procedures or the anticipated well conditions will not place demands above its rated working pressure and obtain approval from the District Manager.
(h) Plan to use a subsea BOP system in an ice-scour area;	Install the BOP stack in a well cellar. The well cellar must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.
(i) You activate any shear ram and pipe or casing is sheared;	Retrieve, physically inspect, and conduct a full pressure test of the BOP stack after the situation is fully controlled. You must submit to the District Manager a report from a BSEE-approved verification organization certifying that the BOP is fit to return to service.
(j) Need to remove the BOP stack;	Have a minimum of two barriers in place prior to BOP removal. You must obtain approval from the District Manager of the two barriers prior to removal and the District Manager may require additional barriers.
(k) In the event of a deadman or autoshear activation, if there is a possibility of the blind-shear ram opening immediately upon re-establishing power to the BOP stack;	Place the blind-shear ram opening function in the block position prior to re-establishing power to the stack. Contact the District Manager and receive approval of procedures for re-establishing power and functions prior to latching up the BOP stack or re-establishing power to the stack.
(l) If a test ram is to be used;	Conduct the initial BOP test after latching up using a test tool, and test the wellhead/BOP connection to the maximum pressure for the approved ram test for the well. All hydraulically operated BOP components must also be functioned during the well connection test.

If you encounter the following situation:	Then you must . . .
(m) Plan to utilize any other well-control equipment (*e.g.,* but not limited to, subsea isolation device, subsea accumulator module, or gas handler) that is in addition to the equipment required in this subpart;	Contact the District Manager and request approval in your APD or APM. Your request must include a report from a BSEE-approved verification organization on the equipment's design and suitability for its intended use as well as any other information required by the District Manager. The District Manager may impose any conditions regarding the equipment's capabilities, operation, and testing.
(n) You have pipe/variable bore rams that have no current utility or well-control purposes;	Indicate in your APD or APM which pipe/variable bore rams meet these criteria and clearly label them on all BOP control panels. You do not need to function test or pressure test pipe/variable bore rams having no current utility, and that will not be used for well-control purposes, until such time as they are intended to be used during operations.
(o) You install redundant components for well control in your BOP system that are in addition to the required components of this subpart (*e.g.,* pipe/variable bore rams, shear rams, annular preventers, gas bleed lines, and choke/kill side outlets or lines);	Comply with all testing, maintenance, and inspection requirements in this subpart that are applicable to those well-control components. If any redundant component fails a test, you must submit a report from a BSEE-approved verification organization that describes the failure, and confirms that there is no impact on the BOP that will make it unfit for well-control purposes. You must submit this report to the District Manager and receive approval before resuming operations. The District Manager may require additional information.
(p) Need to position the bottom hole assembly, including heavy-weight pipe or collars, and bottom-hole tools across the BOP for tripping or any other operations.	Ensure that the well has been stable for a minimum of 30 minutes prior to positioning the bottom hole assembly across the BOP. You must have, as part of your well-control plan required by § 250.710, procedures that enable the immediate removal of the bottom hole assembly from across the BOP in the event of a well control or emergency situation (for dynamically positioned rigs, your plan must also include steps for when the EDS must be activated) before MASP conditions are reached as defined for the operation.

§ 250.739 What are the BOP maintenance and inspection requirements?

(a) You must maintain and inspect your BOP system to ensure that the equipment functions as designed. The BOP maintenance and inspections must meet or exceed any OEM recommendations, recognized engineering practices, and industry standards incorporated by reference into the regulations of this subpart, including API Standard 53 (incorporated by reference in § 250.198). You must document how you met or exceeded the provisions of API Standard 53, maintain complete records to ensure the traceability of all critical components beginning at fabrication, and record the results of your BOP inspections and maintenance actions. You must make all records available to BSEE upon request.

(b) A complete breakdown and detailed physical inspection of the BOP and every associated system and component must be performed every 5 years. This complete breakdown and inspection may not be performed in phased intervals. A BSEE-approved verification organization is required to be present during the inspection and must compile a detailed report documenting the inspection, including descriptions of any problems and how they were corrected. You must make this report available to BSEE upon request.

(c) You must visually inspect your surface BOP system on a daily basis. You must visually inspect your subsea BOP system, marine riser, and wellhead at least once every 3 days if weather and sea conditions permit. You may use cameras to inspect subsea equipment.

(d) You must ensure that all personnel maintaining, inspecting, or repairing BOPs, or critical components of the BOP system, meet the qualification and training criteria specified by the OEMs and recognized engineering practices.

(e) You must make all records available to BSEE upon request. You must ensure that the rig owner maintains your BOP maintenance, inspection, and repair records on the rig for 2 years from the date the records are created or for a longer period if directed by BSEE. You must maintain all design, maintenance, inspection, and repair records at an onshore location for the service life of the equipment.

Records and Reporting

§ 250.740 What records must I keep?

You must keep a daily report consisting of complete, legible, and accurate records for each well. You must keep records onsite while well operations continue. After completion of operations, you must keep all operation and other well records for the time periods shown in § 250.741 at a location of your choice, except as required in § 250.746. The records must contain complete information on all of the following:

(a) Well operations, all testing conducted, and any real-time monitoring data;

(b) Descriptions of formations penetrated;

(c) Content and character of oil, gas, water, and other mineral deposits in each formation;

(d) Kind, weight, size, grade, and setting depth of casing;

(e) All well logs and surveys run in the wellbore;

(f) Any significant malfunction or problem; and

(g) All other information required by the District Manager.

§ 250.741 How long must I keep records?

You must keep records for the time periods shown in the following table.

You must keep records relating to . . .	Until . . .
(a) Drilling;	90 days after you complete operations.
(b) Casing and liner pressure tests, diverter tests, BOP tests, and real-time monitoring data;	2 years after the completion of operations.

You must keep records relating to . . .	Until . . .
(c) Completion of a well or of any workover activity that materially alters the completion configuration or affects a hydrocarbon-bearing zone.	You permanently plug and abandon the well or until you assign the lease and forward the records to the assignee.

§ 250.742 What well records am I required to submit?

You must submit to BSEE copies of logs or charts of electrical, radioactive, sonic, and other well logging operations; directional and vertical well surveys; velocity profiles and surveys; and analysis of cores. Each Region will provide specific instructions for submitting well logs and surveys.

§ 250.743 What are the well activity reporting requirements?

(a) For operations in the BSEE GOM OCS Region, you must submit Form BSEE–0133, Well Activity Report (WAR), to the District Manager on a weekly basis. The reporting week is defined as beginning on Sunday (12 a.m.) and ending on the following Saturday (11:59 p.m.). This reporting week corresponds to a week (Sunday through Saturday) on a standard calendar. Report any well operations that extend past the end of this weekly reporting period on the next weekly report. The reporting period for the weekly report is never longer than 7 days, but could be less than 7 days for the first reporting period and the last reporting period for a particular well operation. Submit each WAR and accompanying Form BSEE–0133S, Open Hole Data Report, to the BSEE GOM OCS Region no later than close of business on the Friday immediately after the closure of the reporting week. The District Manager may require more frequent submittal of the WAR on a case-by-case basis.

(b) For operations in the Pacific or Alaska OCS Regions, you must submit Form BSEE–0133, WAR, to the District Manager on a daily basis.

(c) The WAR must include a description of the operations conducted, any abnormal or significant events that affect the permitted operation each day within the report from the time you begin operations to the time you end operations, any verbal approval received, the well's as-built drawings, casing, fluid weights, shoe tests, test pressures at surface conditions, and any other information required by the District Manager. For casing cementing operations, indicate type of returns (*i.e.,* full, partial, or none). If partial or no returns are observed, you must indicate how you determined the top of cement. For each report, indicate the operation status for the well at the end of the reporting period. On the final WAR, indicate the status of the well (completed, temporarily abandoned, permanently abandoned, or drilling suspended) and the date you finished such operations.

§ 250.744 What are the end of operation reporting requirements?

(a) Within 30 days after completing operations, except routine operations as defined in § 250.601, you must submit Form BSEE–0125, End of Operations Report (EOR), to the District Manager. The EOR must include a listing, with top and bottom depths, of all hydrocarbon zones and other zones of porosity encountered with any cored intervals; details on any drill-stem and formation tests conducted; documentation of successful negative pressure testing on wells that use a subsea BOP stack or wells with mudline suspension systems; and an updated schematic of the full wellbore configuration. The schematic must be clearly labeled and show all applicable top and bottom depths, locations and sizes of all casings, cut casing or stubs, casing perforations, casing rupture discs (indicate if burst or collapse and rating), cemented intervals, cement plugs, mechanical plugs, perforated zones, completion equipment, production and isolation packers, alternate completions, tubing, landing nipples, subsurface safety devices, and any other information required by the District Manager. The EOR must indicate the status of the well (completed, temporarily abandoned, permanently abandoned, or drilling suspended) and the date of the well status designation. The wells' status date is subject to the following:

(1) For surface well operations and riserless subsea operations, the operations end date is subject to the discretion of the District Manager; and

(2) For subsea well operations, the operations end date is considered to be the date the BOP is disconnected from the wellhead unless otherwise specified by the District Manager.

(b) You must submit public information copies of Form BSEE–0125 according to § 250.186(b).

§ 250.745 What other well records could I be required to submit?

The District Manager or Regional Supervisor may require you to submit copies of any or all of the following well records:

(a) Well records as specified in § 250.740;

(b) Paleontological interpretations or reports identifying microscopic fossils by depth and/or washed samples of drill cuttings that you normally maintain for paleontological determinations. The Regional Supervisor may issue a Notice to Lessees that sets forth the manner, timeframe, and format for submitting this information;

(c) Service company reports on cementing, perforating, acidizing, testing, or other similar services; or

(d) Other reports and records of operations.

§ 250.746 What are the recordkeeping requirements for casing, liner, and BOP tests, and inspections of BOP systems and marine risers?

You must record the time, date, and results of all casing and liner pressure tests. You must also record pressure tests, actuations, and inspections of the BOP system, system components, and marine riser in the daily report described in § 250.740. In addition, you must:

(a) Record test pressures on pressure charts;

(b) Require your onsite lessee representative, designated rig or contractor representative, and pump operator to sign and date the pressure charts and daily reports as correct;

(c) Document on the daily report the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. For subsea BOP systems, you must also record the closing times for annular and ram BOPs. You may reference a BOP test plan if it is available at the facility;

(d) Identify on the daily report the control station and pod used during the test (identifying the pod does not apply to coiled tubing and snubbing units);

(e) Identify on the daily report any problems or irregularities observed during BOP system testing and record actions taken to remedy the problems or irregularities. Any leaks associated with the BOP or control system during testing are considered problems or irregularities and must be reported immediately to the District Manager, and documented in the WAR. If any problems or irregularities are observed during testing, operations must be suspended until the District Manager determines that you may continue; and

(f) Retain all records, including pressure charts, daily reports, and referenced documents pertaining to tests, actuations, and inspections at the facility for the duration of the operation. After completion of the operation, you must retain all the records listed in this section for a period of 2 years at the facility. You must also retain the records at the lessee's field office nearest the facility or at another location available to BSEE. You must make all the records available to BSEE upon request.

■ 41. Revise § 250.1612 to read as follows:

§ 250.1612 Well-control drills.

Well-control drills must be conducted for each drilling crew in accordance with the requirements set forth in § 250.711 of this part or as approved by the District Manager.

■ 42. Amend § 250.1703 by:

■ a. Revising paragraphs (b) and (e);

■ b. Redesignating paragraph (f) as paragraph (g); and

■ c. Adding a new paragraph (f).

The revisions and addition read as follows:

§ 250.1703 What are the general requirements for decommissioning?

* * * * *

(b) Permanently plug all wells. All packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198);

* * * * *

(e) Clear the seafloor of all obstructions created by your lease and pipeline right-of-way operations;

(f) Follow all applicable requirements of subpart G; and

* * * * *

■ 43. Amend § 250.1704 by revising paragraph (g) and adding paragraph (h) to read as follows:

§ 250.1704 When must I submit decommissioning applications and reports?

* * * * *

Decommissioning applications and reports	When to submit	Instructions
* *	* * *	* *
(g) Form BSEE–0124, Application for Permit to Modify (APM). The submission of your APM must be accompanied by payment of the service fee listed in § 250.125;	(1) Before you temporarily abandon or permanently plug a well or zone,	(i) Include information required under §§ 250.1712 and 250.1721. (ii) When using a BOP for abandonment operations, include information required under § 250.731.
	(2) Before you install a subsea protective device,	Refer to § 250.1722(a).
	(3) Before you remove any casing stub or mud line suspension equipment and any subsea protective device,	Refer to § 250.1723.
(h) Form BSEE–0125, End of Operations Report (EOR);	(1) Within 30 days after you complete a protective device trawl test,	Include information required under § 250.1722(d).
	(2) Within 30 days after you complete site clearance verification activities,	Include information required under § 250.1743(a).

§ 250.1705 [Removed and Reserved]

■ 44. Remove and reserve § 250.1705.

■ 45. Amend § 250.1706 by:

■ a. Revising the section heading;

■ b. Removing paragraphs (a) through (e); and

■ c. Redesignating paragraph (f) through (h) as paragraphs (a) through (c). The revision reads as follows:

§ 250.1706 Coiled tubing and snubbing operations.

* * * * *

§§ 250.1707 through 250.1709 [Removed and Reserved]

■ 46. Remove and reserve §§ 250.1707 through 250.1709.

■ 47. In § 250.1715, revise paragraph (a)(3)(iii)(B) to read as follows:

§ 250.1715 How must I permanently plug a well?

* * * * *

(a) * * *

(3) * * *

(iii) * * *

(B) A casing bridge plug set 50 to 100 feet above the top of the perforated interval and at least 50 feet of cement on top of the bridge plug;

* * * * *

§ 250.1717 [Removed and Reserved]

■ 48. Remove and reserve § 250.1717.

§ 250.1721 [Amended]

■ 49. Amend § 250.1721 by removing paragraph (g) and redesignating paragraph (h) as paragraph (g).

[FR Doc. 2015–08587 Filed 4–13–15; 4:15 pm]

BILLING CODE 4310–VH–P