DEPARTMENT OF THE INTERIOR

Bureau of Safety and Environmental Enforcement

30 CFR Part 250

[Docket ID: BSEE–2018–0002; 189E1700D2 ET1SF0000.PSB000 EEEE500000]

RIN 1014–AA39

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

AGENCY: Bureau of Safety and Environmental Enforcement, Interior.

ACTION: Proposed rule.

SUMMARY: The Bureau of Safety and Environmental Enforcement (BSEE) is proposing to revise existing regulations for well control and blowout preventer systems. This proposed rule would revise requirements for well design, well control, casing, cementing, real-time monitoring (RTM), and subsea containment. These revisions modify regulations pertaining to offshore oil and gas drilling, completions, workovers, and decommissioning in accordance with Executive and Secretary of the Interior's Orders to ensure safety and environmental protection, while correcting errors and reducing certain unnecessary regulatory burdens imposed under the existing regulations. Accordingly, after thoroughly reexamining the original Blowout Preventer Systems and Well Control final rule (WCR), experiences from the implementation process, and BSEE policy, BSEE proposes to amend, revise, or remove current regulatory provisions that create unnecessary burdens on stakeholders while ensuring safety and environmental protection. The proposed regulations would also address various issues and errors that were identified during the implementation of the recent rulemaking on these issues.

DATES: Submit comments by July 10, 2018. BSEE may not fully consider comments received after this date. You may submit comments to the Office of Management and Budget (OMB) on the information collection burden in this proposed rule by June 11, 2018. The deadline for comments on the information collection burden does not affect the deadline for the public to comment to BSEE on the proposed regulations.

ADDRESSES: You may submit comments on the rulemaking by any of the following methods. Please use the Regulation Identifier Number (RIN) 1014–AA39 as an identifier in your message. See also Public Availability of Comments under Procedural Matters.

- *Federal eRulemaking Portal: http://www.regulations.gov.* In the entry titled Enter Keyword or ID, enter BSEE–2018–0002 then click search. Follow the instructions to submit public comments and view supporting and related materials available for this rulemaking. BSEE may post all submitted comments.
- The American Petroleum Institute (API) provides free online public access to view read only copies of its key industry standards, including a broad range of technical standards. All API standards that are safety-related and that are incorporated into Federal regulations are available to the public for free viewing online in the Incorporation by Reference Reading Room on API's website at: *http://publications.api.org.*[1] In addition to the free online availability of these standards for viewing on API's website, hardcopies and printable versions are available for purchase from API. The API website address to purchase standards is: *http://www.api.org/publications-standards-and-statistics/publications/government-cited-safety-documents.*
- The International Organization for Standardization (ISO) creates documents that provide requirements, specifications/government-cited-safety documents. ISO creates documents that provide requirements, specifications, guidelines or characteristics that can be used consistently to ensure that materials, products, processes and services are fit for their purposes. All ISO International Standards are available at the ISO Store for purchase, *https://www.iso.org/store.html.*
- For the convenience of members of the viewing public who may not wish to purchase copies or view these incorporated documents online, they may be inspected at BSEE's office, 45600 Woodland Road, Sterling, Virginia 20166, or by sending a request by email to *regs@bsee.gov.*
- Send comments on the information collection in this rule to: Interior Desk Officer 1014–0028, Office of Management and Budget; 202–395–5806 (fax); email: *oira_submission@omb.eop.gov.* Please send a copy to BSEE.

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. In order for BSEE to withhold from disclosure your personal identifying information, you must identify any information contained in the submittal of your comments that, if released, would constitute a clearly unwarranted invasion of your personal privacy. You must also briefly describe any possible harmful consequence(s) of the disclosure of information, such as embarrassment, injury, or other harm. 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.

FOR FURTHER INFORMATION CONTACT: For technical questions contact Fred Brink, GOMR District Operations Support, (504) 736–2400, or by email: *OMM_DFO_DOS@bsee.gov*; for procedural questions contact Kirk Malstrom, Regulations and Standards Branch, (202) 258–1518, or by email: *regs@bsee.gov.*

SUPPLEMENTARY INFORMATION:

Executive Summary

In the immediate aftermath of the *Deepwater Horizon* incident in 2010, BSEE adopted several recommendations from multiple investigation teams in order to improve the safety of offshore operations. Subsequently, BSEE published the Blowout Preventer Systems and Well Control final rule (WCR) on April 29, 2016. The WCR consolidated the equipment and operational requirements for well control into one part of BSEE's regulations; enhanced blowout preventer (BOP), well design, and modified well-control requirements; and incorporated certain industry technical standards. Most of the original WCR provisions became effective on July 28, 2016.

Although the WCR addressed a significant number of issues that were identified during the analysis of the *Deepwater Horizon* incident, BSEE recognized that BOP equipment and systems continue to improve technologically and well control processes also evolve. Therefore, since the WCR became effective in 2016, BSEE has continued to engage with the offshore oil and gas industry, Standards Development Organizations (SDOs), and other stakeholders. During the course of these engagements, BSEE identified issues and stakeholders expressed a

[1] To view these standards online, go to the API publications website at: *http://publications.api.org.* You must then log-in or create a new account, accept API's ''Terms and Conditions,'' click on the ''Browse Documents'' button, and then select the applicable category (*e.g.,* ''Exploration and Production'') for the standard(s) you wish to review.

variety of concerns regarding the implementation of the WCR. For instance, oil and natural gas operators raised concerns about certain regulatory provisions that impose undue burdens on their industry, but do not significantly enhance worker safety or environmental protection (*e.g.,* how RTM is monitored and utilized onshore, a strictly enforced 0.5ppg drilling margin, having requirements inconsistent with API Standard 53—an American National Standards Institute (ANSI) accredited, voluntary consensus standards development organization, and delays waiting for certain BSEE approvals during cementing operations). Other stakeholders suggested that certain regulatory requirements do not properly account for advances or limitations in technology and processes. Further, BSEE received numerous questions regarding the proper interpretation and application of provisions viewed to be unclear or ambiguous, requiring BSEE to provide substantial informal guidance regarding the terms of the WCR.

Accordingly, after thoroughly reexamining the original WCR, experiences from the implementation process, and BSEE policy, BSEE proposes to amend, revise, or remove current regulatory provisions that create unnecessary burdens on stakeholders while ensuring safety and environmental protection. The proposed regulatory changes also reflect BSEE's consideration of the public comments and stakeholders' recommendations pertaining to the requirements applicable to offshore oil and gas drilling, completions, workovers, and decommissioning. This proposed rulemaking would revise regulatory provisions in Subparts A, B, D, E, F, G, and Q on topics such as, but not limited to:

Notifications and submittals to BSEE;
Drilling margins;
Lift boats;
Real-time monitoring;
BSEE Approved Verification Organizations (BAVOs);
Accumulator systems;
BOP and control station testing;
Coiled tubing; and
Mechanical barriers (packers and bridge plugs).

BSEE utilized the best available and most pertinent data to analyze the economic impact of the proposed changes. That analysis indicates that the estimated overall economic impact will benefit the industry over the next 10 years because of the substantial reduction in compliance costs while ensuring safety and environmental protection.

In keeping with the Executive and Secretary's Orders, BSEE undertook a review of the 2016 Well Control Final Rule with a view toward the policy direction of encouraging energy exploration and production on the OCS and reducing unnecessary regulatory burdens while ensuring that any such activity is safe and environmentally responsible. BSEE carefully analyzed all 342 provisions of the 2016 Well Control Final Rule, and determined that only 59 of those provisions—or less than 18% of the 2016 Rule—were appropriate for revision. In the process, BSEE compared each of the proposed changes to the 424 recommendations arising from 26 separate reports from 14 different organizations developed in the wake of and response to the *Deepwater Horizon* disaster, and determined that none of the proposed changes ignores or contradicts any of those recommendations, or would alter any provision of the 2016 Well Control Final Rule in a way that would make the result inconsistent with those recommendations. Further, nothing in this proposed rule would alter any elements of other rules promulgated since *Deepwater Horizon,* including the Drilling Safety Rule (Oct. 2010), SEMS I (Oct. 2010), and SEMS II (April 2013). BSEE's review has been thorough, careful, and tailored to the task of reducing unnecessary regulatory burdens while ensuring that OCS activity is safe and environmentally responsible.

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I. Background

A. BSEE Statutory and Regulatory Authority and Responsibilities

BSEE derives its authority primarily from the Outer Continental Shelf Lands Act (OCSLA), 43 U.S.C. 1331–1356a. Congress enacted OCSLA in 1953, authorizing the Secretary of the Interior (Secretary) to lease the Outer Continental Shelf (OCS) for mineral development, and to regulate oil and gas exploration, development, and production operations on the OCS. The Secretary has delegated authority to perform certain of these functions to BSEE.

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

BSEE's regulatory program covers a wide range of facilities and activities, including drilling, completion, workover, production, pipeline, and decommissioning operations. Drilling, completion, workover, and decommissioning operations are types of well operations that offshore operators [2] perform throughout the OCS. These well operations are the primary focus of this rulemaking.

B. Purpose and Summary of the Rulemaking

This proposed rule would amend and update certain provision of the Blowout Preventer Systems and Well Control regulations and update the regulations to better implement BSEE policy. This proposed rule would fortify the Administration's position towards facilitating energy dominance leading to increased domestic oil and gas production, and reduce unnecessary burdens on stakeholders while ensuring safety and environmental protection. Since 2010, BSEE has promulgated many rulemakings (*e.g.,* Safety and Environmental Management Systems (SEMS) I and II, the final safety measures rule, and the production safety systems final rule) to improve worker safety and environmental protection. Additionally, on April 29, 2016, BSEE published a final rule to consolidate into one part the equipment and operational requirements that were found in various parts of BSEE's regulations pertaining to well control for offshore oil and gas drilling, completions, workovers, and decommissioning (81 FR 25888). That final rule addressed issues relating to

[2] BSEE's regulations at 30 CFR part 250 generally apply to "a lessee, the owner or holder of operating rights, a designated operator or agent of the lessee(s) . . . ," covered by the definition of "you" in § 250.105. For convenience, this preamble will refer to all of the regulated entities as "operators" unless otherwise indicated.

BOP and well-control requirements. More specifically, the final rule incorporated industry standards; adopted reforms to well design, well control, casing, cementing, real-time well monitoring, and subsea containment requirements; and implemented many of the recommendations resulting from various investigations of the *Deepwater Horizon* incident. Most of the provisions of that rulemaking became effective on July 28, 2016.

Since the time the Blowout Preventer Systems and Well Control regulations took effect, oil and natural gas operators have raised various concerns, and BSEE has identified issues during the implementation of the recent rulemaking. The concerns and issues involve certain regulatory provisions that impose undue burdens on oil and natural gas operators, but do not significantly enhance worker safety or environmental protection. BSEE understands the concerns that have been raised, but BSEE also fully recognizes that the BOP and other well-control requirements are critical components in ensuring safety and environmental protection. After thoroughly reexamining the Blowout Preventer Systems and Well Control regulations, BSEE has identified those provisions that can be amended, revised, or removed to reduce significant burdens on oil and natural gas operators on the OCS while ensuring safety and environmental protection. In keeping with the Executive and Secretary's Orders, BSEE undertook a review of the 2016 Well Control Final Rule with a view toward the policy direction of encouraging energy exploration and production on the OCS and reducing unnecessary regulatory burdens while ensuring that any such activity is safe and environmentally responsible. BSEE carefully analyzed all 342 provisions of the 2016 Well Control Final Rule, and determined that only 59 of those provisions—or less than 18% of the 2016 Rule—were appropriate for revision. In the process, BSEE compared each of the proposed changes to the 424 recommendations arising from 26 separate reports from 14 different organizations developed in the wake of and response to the *Deepwater Horizon* disaster, and determined that none of the proposed changes ignores or contradicts any of those recommendations, or would alter any provision of the 2016 Well Control Final Rule in a way that would make the result inconsistent with those recommendations. Further, nothing in this proposed rule would alter any elements of other rules promulgated since *Deepwater Horizon,* including the Drilling Safety Rule (Oct. 2010), SEMS I (Oct. 2010), and SEMS II (April 2013). BSEE's review has been thorough, careful, and tailored to the task of reducing unnecessary regulatory burdens while ensuring that OCS activity is safe and environmentally responsible.

This rulemaking would revise current regulations that impact offshore oil and gas drilling, completions, workovers, and decommissioning activities. The proposed regulations would also address various issues that were identified during the implementation of the current Blowout Preventer Systems and Well Control regulations, as well as numerous questions that have required substantial informal guidance from BSEE regarding the interpretation and application of the provisions. For example, this proposed rulemaking would:

- Clarify the rig movement reporting requirements.
- Clarify and revise the requirements for certain submittals to BSEE to eliminate redundant and unnecessary reporting.
- Clarify the drilling margin requirements.
- Revise section 250.723 by removing references to lift boats from the section.
- Remove certain prescriptive requirements for real time monitoring.
- Replace the use of a BSEE approved verification organization (BAVO) with the use of an independent third party for certain certifications and verifications of BOP systems and components, and remove the requirement to have a BAVO submit a Mechanical Integrity Assessment report for the BOP stack and system.
- Revise the accumulator system requirements and accumulator bottle requirements to better align with API Standard 53.
- Revise the control station and pod testing schedules to ensure component functionality without inadvertently requiring duplicative testing.
- Include coiled tubing and snubbing requirements in Subpart G.
- Revise the text to ensure consistency and conformity across the applicable sections of the regulations.

C. Summary of Documents Incorporated by Reference

This rulemaking would update a document currently incorporated by reference to a newer edition, and add a new standard for incorporation. A brief summary of the proposed changes, 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 provides 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. BOP 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: BOPs including installations for surface and subsea BOPs; choke and kill lines; choke manifolds; control systems; and auxiliary equipment.

This standard also provides new industry best practices related to the use of dual shear rams, maintenance and testing requirements, and 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 Standard 65–part 2, which was issued December 2010. This standard outlines the process for isolating potential flow zones during well construction. The new Standard 65–part 2 enhances the description and classification of well-control barriers, and defines testing requirements for cement to be considered a barrier.

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

The proposed rule would update the incorporated version of this document from the First Edition (dated 2004, reaffirmed 2009) to the Second Edition (dated 2013). This recommended practice provides general recommendations and overall guidance for the design and operation of remotely operated tools (ROT) and remotely operated vehicle (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. One of the main differences between the first edition and second edition of this recommended practice is that the second edition includes provisions on high flow Type D hot stabs.

ISO ISO/IEC 17021–1—Conformity Assessment—Requirements for Bodies Providing Audit and Certification of Management Systems

The proposed rule would incorporate this standard into the regulations by reference for the first time, for purposes of the quality management system certification requirements of section 250.730(d). This standard contains principles and requirements for the competence, consistency, and impartiality of bodies providing audit and certification of all types of management systems. It provides generic requirements for such bodies performing audit and certification in the fields of quality, the environment, and other types of management systems. Incorporation of this standard would provide clarity and consistency surrounding the critical qualifications of entities responsible for certifying quality management systems for the manufacture of BOP stacks.

When a copyrighted publication is incorporated by reference into BSEE regulations, BSEE is obligated to observe and protect that copyright. BSEE provides members of the public with website addresses where these standards may be accessed for viewing—sometimes for free and sometimes for a fee. Standards development organizations decide whether to charge a fee. One such organization, the American Petroleum Institute (API), provides free online public access to view read only copies of its key industry standards, including a broad range of technical standards. All API standards that are safety-related and that are incorporated into Federal regulations are available to the public for free viewing online in the Incorporation by Reference Reading Room on API's website at: *http://publications.api.org.*[3] In addition to the free online availability of these standards for viewing on API's website, hardcopies and printable versions are available for purchase from API. The API website address to purchase standards is: *http://www.api.org/publications-standards-and-statistics/publications/government-cited-safety-documents.*

The International Organization for Standardization (ISO) creates documents that provide requirements, specifications/government-cited-safety documents. ISO creates documents that provide requirements, specifications, guidelines or characteristics that can be used consistently to ensure that materials, products, processes and services are fit for their purposes. All ISO International Standards are available at the ISO Store for purchase, *https://www.iso.org/store.html.*

For the convenience of members of the viewing public who may not wish to purchase copies or view these incorporated documents online, they may be inspected at BSEE's office, 45600 Woodland Road, Sterling, Virginia 20166, or by sending a request by email to *regs@bsee.gov.*

In addition, BSEE is aware of a published addendum to API Standard 53, and a new Standard 53 edition currently under development by API, consistent with international standards. BSEE will continue to evaluate the API addendum and the new edition. At this time, BSEE does not propose to incorporate the API Standard 53 addendum into this proposed rule. However, BSEE is considering incorporating the API Standard 53 addendum in the final rule. BSEE is specifically soliciting comments on whether the API Standard 53 addendum should be included within the documents incorporated by reference. Please provide reasons for your position. If your comment addresses anticipated monetary or operational benefits associated with using the API Standard 53 addendum, please provide any available supporting data. When the new edition of API Standard 53 is finalized by API, BSEE would consider incorporating that edition into future rulemaking as appropriate.

BSEE is also considering potential, technical (non-substantive) revisions to § 250.198 for the purposes of reorganizing and revising that section to make it clearer, more user-friendly, and more consistent with the Office of the Federal Register's (OFR) recommendations for incorporations by reference in Federal regulations. BSEE will continue to consult with OFR regarding its suggestions for specific organizational and language changes to § 250.198 and expects to address such technical revisions in a final rule as soon as possible. BSEE does not anticipate that those potential revisions would have any substantive impact on the proposed incorporations by reference of industry standards discussed in this rule.

D. New Executive and Secretary's Orders

On March 28, 2017, the President issued Executive Order (E.O.) 13783—Promoting Energy Independence and Economic Growth (82 FR 16093). The E.O. directed Federal agencies to review all existing regulations and other agency actions and, ultimately, to suspend, revise, or rescind any such regulations or actions that unnecessarily burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law.

On April 28, 2017, the President issued E.O. 13795—Implementing an America-First Offshore Energy Strategy (82 FR 20815), which directed the Secretary to review the WCR for consistency with the policy set forth in section 2 of E.O. 13795, and to ''publish for notice and comment a proposed rule revising that rule, if appropriate and as consistent with law.'' To further implement E.O. 13795, the Secretary issued Secretary's Order No. 3350 on May 1, 2017, directing BSEE to review the WCR for consistency with E.O. 13795, including preparation of a report ''providing recommendations on whether to suspend, revise, or rescind the rule'' in response to concerns raised by stakeholders that the WCR ''unnecessarily include[s] prescriptive measures that are not needed to ensure safe and responsible development of our OCS resources.''

As part of its response to E.O.s 13783 and 13795, and Secretary's Order No. 3350, and in light of the requests received for clarification and revision of various provisions, BSEE reviewed the WCR and is proposing revisions to the WCR that could reduce unnecessary burdens on industry without impacting key provisions in the rule that have a significant impact on improving safety and equipment reliability.

E. Stakeholder Engagement

Implementation of the Original WCR—BSEE Questions and Answers (Q's and A's)

The Department promulgated the original ''Blowout Preventer Systems and Well Control'' final rule (WCR) in April 2016. Subsequently, during the implementation of the revised regulations, BSEE received numerous questions from stakeholders seeking clarification and guidance concerning the WCR's provisions. The questions covered a vast array of issues and spanned multiple subparts of the regulations.

BSEE reviewed each question it received and decided whether the question presented an issue that was appropriate for Bureau guidance. To the extent a question required guidance or clarification, BSEE provided a response to clarify any potentially confusing language. In addition to deciding on the appropriateness of a question for guidance, BSEE determined whether a question posed was of sufficient public interest to merit broader publication of a response. After finalizing regulatory

[3] To view these standards online, go to the API publications website at: *http://publications.api.org.* You must then log-in or create a new account, accept API's ''Terms and Conditions,'' click on the ''Browse Documents'' button, and then select the applicable category (*e.g.,* ''Exploration and Production'') for the standard(s) you wish to review.

guidance in response to a stakeholder's question, BSEE typically publishes both the question and BSEE's answer on its web page. The information, which reflects BSEE's guidance of the current regulations, may be found at: *https://www.bsee.gov/guidance-and-regulations/regulations/well-control-rule.* BSEE has posted approximately 100 responses on the web page.

BSEE has reexamined the questions and answers pertaining to the original WCR. After careful consideration of all relevant information in the questions and answers, BSEE has determined that certain provisions of the original rule should be revised to support the goals of the regulatory reform initiative while ensuring safety and environmental protection. Additionally, BSEE's proposed revisions seek to clarify any ambiguity in the regulatory language, eliminate redundancies in the provisions, and align specific requirements more closely with relevant technical standards.

BSEE Public Forum on Well Control and Blowout Preventer Rule

To ensure a complete and thorough review of the WCR, BSEE has solicited input from interested parties to identify potential revisions to the rule that would significantly reduce regulatory burdens without significantly reducing safety and environmental protection on the OCS. BSEE held a public forum on September 20, 2017, in Houston, Texas. More than 110 participants attended and provided comments and suggestions. A summary of registrants included:

- Federal agencies;
- Media;
- Oil and gas companies;
- Classification societies;
- Trade associations;
- Environmental groups; and
- Equipment manufacturers.

Additionally, there were eight presentations made at the forum. These presentations are available at *https://www.bsee.gov/guidance-and-regulations/regulations/well-control-rule/public%20forum.*

II. Section-by-Section Discussion of Proposed Changes

BSEE is proposing to revise the following regulations:

Subpart A—General

Documents Incorporated by Reference (§ 250.198)

BSEE would revise paragraph (h)(63), which incorporates API Standard 53, Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition, November 2012, to add a new cross reference to § 250.734. The changes to this paragraph are administrative and merely reflect substantive changes made to § 250.734, addressed further at the corresponding location in the section-by-section discussion.

BSEE would revise paragraph (h)(78), which incorporates API Standard 65—Part 2, Isolating Potential Flow Zones During Well Construction; Second Edition, December 2010, to add a new cross reference to § 250.420(a)(6). The changes to this paragraph are administrative. For discussion of the effects on the regulatory requirements of incorporating this document, refer to § 250.420(a)(6).

BSEE would also revise paragraph (h)(94) to update the incorporation of API RP 17H to the second edition. The changes to this paragraph are administrative. For discussion of the effects on the regulatory requirements of incorporating this document, refer to § 250.734(a)(4). BSEE has reviewed the differences between the first and second editions of API RP 17H. The API RP 17H second edition was mostly rearranged to clarify and consolidate similar topics covered in the first edition. The second edition now includes the following sections: Subsea intervention concepts, subsea intervention systems design recommendations, ROV interfaces, materials, subsea markings, and validation and verification. These sections are mostly a reorganization of the content of the first edition with minor changes to the design recommendations. The most significant change from the first edition to the second edition was the addition of the Type D connection to the ROV interface section. The Type D connection is intended for large bore, high circulation capabilities and is limited to the maximum rated pressure of 5,000 psi. This Type D connection allows the ROV hot stab to meet the API Standard 53 closing timing requirements, which API RP 17H first edition did not accomplish.

BSEE would add new paragraph (m)(2) for the International Organization for Standardization (ISO) 17021 to update the erroneous standard incorporated in the original WCR. For discussion of the effects on the regulatory requirements of incorporating this document, refer to § 250.730(d) and the associated section-by-section discussion.

Subpart B—Plans and Information

What must the DWOP contain? (§ 250.292)

This rulemaking would revise paragraph (p) by clarifying the free standing hybrid riser (FSHR) requirements and removing the requirement for certification of the tether system and connection accessories by an approved classification society or equivalent. Based on BSEE experience during the implementation of the original WCR, these revisions to paragraph (p) would clarify the focus of the requirements for FSHR systems that involve a buoyancy air can suspended from the top of the riser, regardless of the manner of connection, to avoid confusion over whether a specific component type would be considered 'critical' or not. The requirements in existing § 250.292(p)(2) and (p)(3) would be removed because the detailed information specified on the FSHR design, fabrication, installation, and load cases is already required by the relevant portions of the platform verification program (PVP) in § 250.910(b), and in §§ 250.1002(b)(5) and 250.1007(a)(4)(ii). This would reduce the burden on operators by eliminating the requirement to submit the same or very similar information on an FSHR system through more than one regulatory permitting process. Section 250.292 paragraphs (p)(4) and (p)(5) would be redesignated as § 250.292 paragraphs (p)(2) and (p)(3), and their language would be revised to align with the clarification in paragraph (p). The requirements in § 250.292(p)(6) would be removed altogether, because they are duplicative of the certification that any permanent pipeline riser installation and its tensioning systems will undergo via the Certified Verification Agent (CVA) requirements of § 250.911, in connection with the PVP.

Subpart D—Oil and Gas Drilling Operations

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

This rulemaking would add in paragraph (g) a parenthetical clarification of ''surface and downhole'' after ''proposed drilling fluid weights'', to ensure the operator includes the weight of the drilling fluid in both places. This clarifies the information the operator has previously been required to provide, without adding a new burden, and improves the safety of the drilling operation by ensuring the drilling fluid weight is fully evaluated and appropriate for the estimated bottom hole pressures.

What must my drilling prognosis include? (§ 250.414)

This proposed rule would revise paragraph (c)(3) of this section to add the words ''and analogous'' before ''well behavior observations'' and '', if available'' at the end of paragraph (c)(3) of this section. This minor wording change would ensure that operators use available data from wells with similar conditions as the well being drilled when determining the pore pressure and fracture gradient to ensure accuracy and safety when establishing the drilling margin. BSEE is specifically soliciting comments about the effectiveness of the use of related analogous data and how the pore pressure and fracture gradient are determined without related analogous data. Please provide reasons for your position.

In the proposed rule text, the drilling margin requirements are mostly unchanged. The current regulations allow for a deviation from the default 0.5 pound per gallon (ppg) drilling margin. The deviation does not have to be submitted as an alternate procedure or departure request; rather, it may be submitted with the Application for Permit to Drill (APD) along with the supporting justifications. BSEE is currently approving margins other than 0.5 ppg based on specific well conditions. BSEE is working to provide consistent approval throughout the regions and districts, and, as described more fully below, BSEE is specifically soliciting comments about the process to deviate from the 0.5 ppg drilling margin.

The purpose of the drilling margin is to ensure that the drilling fluid weight used allows for some variability in the pore pressure and fracture gradient, ensuring the safety of drilling operations. In 2011, the National Academy of Engineering and National Research Council of the National Academies recommended that ''[d]uring drilling, rig personnel should maintain a reasonable margin of safety between the equivalent circulating density and the density that will cause wellbore fracturing.'' Macondo Well *Deepwater Horizon* Blowout—Lessons for Improving Offshore Drilling Safety (NAE Report), Recommendation 2.2 (p. 43). The NAE Report stated further that ''until a reasonable standard is established, industry should design the ECD [equivalent circulating density] so that the difference between the ECD and the fracture mud weight is a minimum of 0.5 ppg . . . Additional evaluations and analyses should be performed to establish an appropriate standard for this margin of safety.'' *Id.* The Department's 2011 joint investigation team report (DOI JIT Report) regarding the causes of the April 20, 2010, Macondo Well blowout recommended that BSEE define the term ''safe drilling margin(s)'' and that such a definition should ''encompass pore pressure, fracture gradient and mud weight.'' The Bureau of Ocean Energy Management, Regulation and Enforcement Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout (DOI JIT Report), Recommendation 3 (p. 202). Thus, the NAE Report and the DOI JIT Report recommended additional evaluations, analyses, and definition of what a safe drilling margin is. In the 2016 final well control rule preamble, BSEE cited this JIT Report recommendation and the bureau's prior typical reliance on a minimum of 0.5 ppg below the lower casing shoe pressure integrity test or the lowest estimated fracture gradient as an appropriate safe drilling margin and as the basis for including this as the default requirement in the current section 250.414(c). 81 FR 25888, 25894 (April 29, 2016). Section 250.414(c) also allows for using an equivalent downhole mud weight, provided that the operator submitted adequate documentation justifying the use of an alternative equivalent downhole mud weight.

Since the WCR became effective, BSEE's records show that there have been 305 wells drilled. Of those wells, BSEE has approved operators' use of drilling margins that are less than 0.5 ppg for 32 wells, 31 of which were in deep water. Even though these 32 wells represent only 10 percent of the total wells drilled in that time frame, the number is significant enough for BSEE to consider whether it should further refine the approach it is taking in the current regulations or whether it should adhere to its practice of identifying a specific drilling margin with an avenue for allowing operators to submit adequate documentation justifying the use of a different drilling margin, such as risk modeling data, off-set well data, analog data, and seismic data.

The Explanatory Statement for the 2017 Consolidated Appropriations Act, Public Law 115–31 (May 5, 2017), also recommended that BSEE consider revising the 2016 WCR. It stated:

> *Blowout Preventer Systems and Well Control Rule.*—The Committees encourage the Bureau to evaluate information learned from additional stakeholder input and ongoing technical conversations to inform implementation of this rule. To the extent additional information warrants revisions to the rule that require public notice and comment, the Bureau is encouraged to follow that process to ensure that offshore operations promote safety and protect the environment in a technically feasible manner.

163 Cong. Rec. H3881 (daily ed. May 3, 2017).

For these reasons, BSEE is requesting comment and further statistical analysis from stakeholders about whether the 0.5 ppg drilling margin in this proposed rule should be revised or removed. BSEE solicits comments on alternatives to the current set 0.5 ppg drilling margin. Specifically, BSEE requests comment on replacing it with a more performance-based standard under which the approved safe drilling margin is established on a case-by-case basis for each well, based on data and analysis particular to that well, through the permitting process. BSEE also requests comment on potentially providing for a different drilling margin or multiple drilling margins that are specific to the conditions in which the wells are drilled, such as if the well is drilled in deep water or shallow water. BSEE further requests comment on whether removal of a specific reference to a 0.5 ppg standard from the regulation may be appropriate. For example, the standard establishes a prescriptive margin without an in-depth analysis of appropriate margins for potential hole sections, which must take into account factors, such as cutting loads, equivalent downhole mud weight, and fluid temperatures and pressures. Further, enforcing a prescriptive minimum margin can force operators to encroach on pore pressure, which might result in unintended kicks. These types of considerations may suggest that a more case-by-case approach toward the establishment of appropriate safe drilling margins for particular wells through the permitting process would be preferable. Consequently, BSEE specifically solicits comments regarding the potential removal of the specific reference to a 0.5 ppg drilling margin from § 250.414(c) and its replacement with a more performance based, case-by-case standard for the establishment of appropriate safe drilling margins through the well permitting process.

BSEE also requests comment on the criteria that BSEE could use to apply alternative approaches, such as an operator demonstrating that a well is a development well as opposed to an exploratory well. To utilize this alternative option, the rulemaking could specify what documentation operators would need to submit with the APD in order to provide adequate justification. BSEE requests comment on what supplemental data would provide an adequate level of justification for deviating from the 0.5 ppg drilling margin under identified circumstances, such as requiring the submission of offset well data, analog data, seismic data, and decision modeling.

BSEE also requests comment on whether there are situations where drilling can continue prior to receiving alternative safe drilling margin approval from BSEE. BSEE requests comment on (1) whether there are situations where, despite not being able to maintain the approved safe drilling margin, an operator's continued drilling with an alternative drilling margin creates little risk; (2) the criteria that BSEE should use to define those situations and the available alternative drilling margins; and (3) what level of follow-up reporting (*e.g.* submitting a follow-up notice to BSEE within a specified time frame) would be appropriate. Such an approach could provide assurance that an operator, with the appropriate level of justification, could continue to drill as real time data is evaluated, and would largely be designed to add more clarity to the existing option(s) provided by § 250.414(c)(2). This would provide a proactive approach to managing risk and ensuring safe operations, while also providing increased investment certainty for the regulated community.

In addition, BSEE could add the words ''and analogous'' before ''well behavior observations'' and '', if available'' at the end of paragraph (c)(3) of this section. This minor wording change could ensure that operators use available data from wells with similar conditions as the well being drilled when determining the pore pressure and fracture gradient to ensure accuracy and safety when establishing the drilling margin. BSEE is specifically soliciting comments about the effectiveness of the use of related analogous data and how the pore pressure and fracture gradient are determined without related analogous data. Please provide reasons for your position.

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

BSEE is proposing to incorporate by reference API Standard 65–Part 2 in paragraph (a)(6) of this section for purposes of defining the standards governing centralization. This would clarify the intent of the current centralization requirements by adopting the methods described in API Standard 65–Part 2 to ensure proper centralization during cementing. BSEE would add the reference to API Standard 65–Part 2 based upon its evaluation of the original WCR implementation and industry's recent questions concerning the applicability of this standard. Centralization is important for cement jobs, as it ensures the casing is centered in the hole and that there is enough space between the casing and the wellbore for the cement to form a uniform barrier to help minimize the risk of cement failure. BSEE has determined that the standards set forth in API Standard 65–Part 2 properly ensure adequate centralization and provide clearer guidelines for operators than the current regulatory language.

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

BSEE proposes to make minor revisions in paragraphs (c), (d), (e), and (f) clarifying that all length requirements are to be taken from measured depth. This clarification of the existing regulatory requirements would provide consistency for planning and permitting purposes.

Paragraph (f) would also be revised by removing the specifics of the listed example regarding when a liner is used as intermediate casing. The example is redundant because it restates the same information already contained in this section. This deletion would not change the applicability or substance of the requirements.

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

This rulemaking would revise paragraphs (a) and (b) by removing the words ''and cementing'' after ''upon successfully installing''. Revisions to this section are necessary because there are many situations in the design of the casing or liner string running tool where the latching or lock down mechanism is automatically engaged upon installing the string. BSEE has received many alternate procedure requests to accommodate these situations since publication of the original WCR. This change would not impact safety because BSEE is still requiring these mechanisms to be engaged upon successful installation of the casing or liner. The proposed change would allow more flexibility on an operational case-by-case basis in determining the appropriate time to engage these mechanisms and would also reduce the number of alternate procedure requests submitted to BSEE for approval.

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

BSEE is proposing to revise paragraph (c) to include the term ''unplanned'' when describing the lost returns that provide indications of an inadequate cement job. This revision would minimize the number of unnecessary revised permits submitted to BSEE for approval. Current cementing practices utilize improved well modelling to identify and account for zones that may have anticipated losses. It is unnecessary to submit a revised APD to address lost returns for a well cementing program that has been designed for those occurrences. Any unexpected losses would require locating top of cement and determining whether the cement job is adequate.

Existing paragraph (c)(iii) would be redesignated as paragraph (c)(iv). A new paragraph (c)(iii) would be added to allow the use of tracers in the cement, and logging the tracers' location prior to drill out, as an alternative approach for locating the top of cement. The original WCR did not address this approach, however based upon BSEE experience this addition would provide more viable options and flexibility for locating top of cement to help minimize rig down time running in and out of the hole multiple times, without compromising safety.

Paragraph (d) would be revised to clarify that, if there is an inadequate cement job, operators are required to comply with § 250.428(c)(1). The original WCR did not address this provision, however based upon BSEE experience this revision would help assess the overall cement job to allow for improved planning of remedial actions.

This rulemaking would also revise paragraph (d) to allow the preapproval of remedial cementing actions through a contingency plan within the original approved permit; however, if the remedial actions have not already been approved by BSEE, clarification was added directing submittal of the remedial actions in a revised permit for BSEE review and approval. The original WCR did not address this provision, however based upon BSEE experience, BSEE is proposing to allow the remedial actions to be included as contingency plans in the original permit to minimize the time necessary for operators to commence approved remedial cementing actions, and to reduce burdens on operators and BSEE from multiple submissions. If BSEE has already approved the remedial cementing actions in the original permit, additional BSEE approval is not required unless they deviate from the approved actions. BSEE will still receive information regarding any remedial cementing actions taken in Well Activity Reports.

Based upon BSEE experience with the implementation of the original WCR, BSEE has determined that allowing the professional engineer (PE) to certify the remedial cementing actions in the contingency plan within the original permit would help streamline the permitting process and reduce delays to remedial actions without compromising safety. The proposed revision to this paragraph would eliminate the requirement for a PE certification for any changes to the well program so long as the changes were already approved in the permit. This would result in less rig down time waiting for PE certifications before beginning initial remedial actions. In conjunction with the approval of the remedial actions BSEE requires a PE certification for any changes to the well program. These proposed revisions would minimize the number of revised permits submitted to BSEE for approval, reducing burdens on operators and BSEE.

What are the diverter actuation and testing requirements? (§ 250.433)

This rulemaking would revise paragraph (b) to modify requirements for subsequent diverter testing by allowing partial activation of the diverter element and not requiring a flow test. The original WCR did not address this provision, however based upon BSEE experience these changes would codify longstanding BSEE policy and minimize the number of alternate procedure requests submitted to BSEE. Full actuation of the diverter element and flow tests are unnecessary with subsequent testing because partial actuation of the element sufficiently demonstrates functionality of the element, and a full flow test would be originally verified on the initial test. These changes would also help minimize the possibility of accidental discharge of mud overboard.

What are the requirements for directional and inclination surveys? (§ 250.461)

This proposed rule would revise paragraph (b) by extending the maximum permitted survey intervals during angle-changing portions of directional wells from 100 feet to 180 feet. This would account for the majority of the pipe stand lengths and would address developments that BSEE has needed to accommodate through alternative approvals since before the original WCR. Most rigs have upgraded the derrick height to account for the increase in pipe stand lengths to improve drilling efficiency. The pipe stands have routinely become greater than 100 feet, with some pipe stands being as high as 180 feet. Increasing the survey interval to correlate with the now common pipe stand lengths would help improve rig efficiency while drilling. This revision would also minimize the number of alternate procedure requests submitted to BSEE in APDs. BSEE does not expect these revisions to reduce safety because of the rationale previously stated. BSEE currently, when appropriate, approves survey intervals based on the use of such pipe stand lengths through the alternate procedure request and approval process. These revisions would not result in any real changes in current survey operations, only removing the added process of operators submitting for approval an alternate procedure to use surveys associated with 180 foot pipe stand lengths.

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

Paragraph (b) of this section would be revised to clarify that the source control and containment equipment (SCCE) to which operators need to have access is based on the determinations regarding source control and containment capabilities required in § 250.462(a), and that the identified list of equipment represents examples of the types of SCCE that may be determined appropriate rather than universal requirements. Based upon BSEE experience with the implementation of the original WCR, this revision would help ensure that appropriate SCCE is available for the specific corresponding well rather than requiring every possible type of SCCE regardless of the well-specific determinations.

Paragraph (e)(1)(ii) would be revised to remove ''a BSEE approved verification organization'' and replace it with ''an independent third party'' that meets the requirements of § 250.732(b). For a discussion on the changes from a BAVO to an independent third party, see the section-by-section discussion of § 250.732.

Proposed revisions to paragraph (e)(3) would clarify that subsea utility equipment utilized solely for containment operations must be available for inspection at all times. Paragraph (e)(4) would also be revised to clarify that it is applicable only to collocated equipment identified in the Regional Containment Demonstration (RCD) or Well Containment Plan and not all collocated equipment. The proposed revisions to both paragraphs (e)(3) and (e)(4) would help ensure that the applicable respective equipment is available for inspection. BSEE recognizes that some of the equipment used for containment is used for other types of operations on the OCS and would be available for inspection when in use during other well operations.

Subpart E—Oil and Gas Well-Completion Operations

Tubing and Wellhead Equipment (§ 250.518)

This rulemaking would revise paragraph (e)(1) by clarifying that only permanently installed packers or bridge plugs that are qualified as mechanical barriers are required to comply with ANSI/API Spec. 11D1. Based upon BSEE experience with the implementation of the original WCR, including questions BSEE received from operators, this revision would codify BSEE's policy to ensure that the required mechanical barriers in a well are held to a higher standard than other common packers or bridge plugs used for various other well-specific conditions and completions design. Furthermore, BSEE is aware that certain packers and bridge plugs cannot meet the specifications of ANSI/API Spec. 11D1. BSEE does not expect these revisions to reduce safety. The proposed change would ensure that the packers and bridge plugs utilized as required mechanical barriers are ANSI/API Spec. 11D1 compliant, while eliminating the need for packers and plugs used for other, non-critical, purposes to meet the standard.

What are the requirements for casing pressure management? (§ 250. 519)

BSEE would make minimal revisions to this section to update incorrect citations. These revisions are administrative in nature and ensure that the appropriate citations are correctly cross referenced.

How do I manage the thermal effects caused by initial production on a newly completed or recompleted well? (§ 250.522)

BSEE would make minimal revisions to this section to update incorrect citations. These revisions are administrative in nature and ensure that the appropriate citations are correctly cross referenced.

When am I required to take action from my casing diagnostic test? (§ 250.525)

BSEE would make minimal revisions to paragraph (d) of this section to update incorrect citations. These revisions are administrative in nature and ensure that the appropriate citations are correctly cross referenced.

What do I submit if my casing diagnostic test requires action? (§ 250.526)

BSEE would make minimal revisions to this section to update incorrect citations. These revisions are administrative in nature and ensure that the appropriate citations are correctly cross referenced.

What if my casing pressure request is denied? (§ 250.530)

BSEE would make minimal revisions to paragraph (b) of this section to update incorrect citations. These revisions are administrative in nature and ensure that the appropriate citations are correctly cross referenced.

Subpart F—Oil and Gas Well-Workover Operations

Definitions (§ 250.601)

This rulemaking would revise the definition of routine operations in this section to make it consistent with the definition of routine operations in § 250.105 by adding paragraph (m) ''acid treatments.'' The original WCR did not address this provision, however based upon BSEE experience, this revision is necessary to help minimize confusion about the definition of routine operations.

Coiled tubing and snubbing operations (§ 250.616)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.750, with minor revisions discussed in connection with that provision. These revisions would help BSEE eliminate inconsistencies between similar requirements throughout different BSEE subparts by consolidating those requirements into Subpart G which is applicable to drilling, completions, workovers, and decommissioning operations.

Tubing and wellhead equipment (§ 250.619)

This rulemaking would revise paragraph (e)(1) by clarifying that only permanently installed packers or bridge plugs that are qualified as mechanical barriers are required to comply with ANSI/API Spec. 11D1. This revision would codify BSEE's policy developed since the WCR, to ensure that the required mechanical barriers in a well are held to a higher standard than other common packers or bridge plugs used for various well specific conditions and completions design. Furthermore, BSEE is aware that certain packers and bridge plugs cannot meet the specifications of ANSI/API Spec. 11D1. BSEE would also add that operators must have two independent barriers, one being mechanical, in the exposed center wellbore prior to removing the tree or well control equipment. This addition would codify existing BSEE policy and add into the workover regulations in Subpart F requirements about mechanical barriers similar to those already found in § 250.720(a). This addition would help ensure the well is properly secured before removal of the tree or well control equipment.

Subpart G—Well Operations and Equipment

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

BSEE proposes to revise this section by adding new paragraphs (g) and (h). BSEE would add paragraph (g) to clarify that reporting is not necessary for rig movements to and from the safe zone during permitted operations. BSEE would also add paragraph (h) to clarify that, if a rig unit is already on a well, BSEE would not require a notification for any additional rig unit movements on that well. This change would not impact safety because BSEE would still receive initial rig movement notifications and would be aware of rig unit locations. The original WCR did not address this provision, however based upon BSEE experience, BSEE determined that these clarifications would minimize the number of duplicative rig movement notifications submitted to BSEE under these particular circumstances.

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

BSEE proposes to revise paragraph (a)(1) to add an impending National Weather Service-named tropical storm or hurricane to the list of example events that would interrupt operations and require notification. Furthermore, BSEE also proposes to add new paragraph (a)(3) to include provisions for testing the applicable BOP or lower marine riser package (LMRP) upon relatch according to § 250.734 paragraphs (b)(2) or (b)(3), respectively, and obtaining BSEE approval before resuming operations. Based upon BSEE experience with the implementation of the original WCR and longstanding policy, these revisions would codify the BSEE storm policy reflected in longstanding guidance and provide clarity for testing when an operator has returned to the location and relatched the BOP or LMRP. These tests help confirm that the BOP or LMRP is properly functional prior to resuming operations after being unlatched due to a storm or other interruption.

This rulemaking would also add new paragraph (d) requiring equipment and capabilities for well intervention. This addition would specify that equipment used solely for well intervention must be readily available for use, maintained in accordance with applicable original equipment manufacturer (OEM) recommendations, and available for inspection by BSEE upon request. BSEE would add this paragraph to ensure that when intervention is necessary on a well, the applicable tools (such as the tree interface tools) are available and ready for their intended use. BSEE is aware of recent instances where intervention was necessary on a particular subsea tree, and the tree-specific unique interface tools were not available to perform the work on that well, delaying the operations.

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

BSEE is proposing to revise the prolonged operations well casing reporting requirements in paragraph (a)(2) of this section to clarify that District Manager approval is not required to resume operations if a successful pressure test was conducted as already approved in the applicable permit. BSEE would also clarify that the successful pressure test results must be documented in the Well Activity Report (WAR). The original WCR did not address the issue of District Manager approval, however based upon BSEE experience, these revisions would minimize the amount of unnecessary rig operational time waiting for separate BSEE approval of the successful pressure test where BSEE has already approved the relevant testing and streamline BSEE approval of associated operations. These revisions would be applicable only if the actions are appropriately planned for and already approved in the associated permit. The pressure tests are conducted to help verify casing integrity. BSEE would also make a minor revision to this paragraph to provide that the calculations are used to ''indicate'' not ''show'' that the well's integrity is above the minimum safety factors. This change is necessary because the calculations do not guarantee or ''show'' integrity; they are used as a way to help determine well integrity. Using the word ''indicate'' removes the definitive statement or assumption that the calculations demonstrate well integrity. BSEE does not expect these revisions to decrease safety because, by approving the test pressure described in the APD, BSEE has determined that any test that successfully meets the pre-approved test pressure for that casing design is sufficient. Therefore, requiring an additional, subsequent approval of the test results before operations may be resumed is redundant and unnecessary and does not improve safety. BSEE will be notified of the test results through the reporting requirements of the WAR.

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 rulemaking would revise this section by removing the phrase ''or lift boat.'' This revision would mostly impact paragraph (c)(3) which requires a shut-in of all producible wells located in the affected wellbay when a lift boat moves within 500 feet of the platform until the lift boat is secured in place and ready to begin operations. Removing the references to lift boats from these requirements would minimize the number of unnecessary well shut-ins and delayed production. Since the original WCR, BSEE reevaluated the lift boat activities, and determined that the vast majority of lift boats used on the OCS are relatively small when compared to the size of a mobile offshore drilling unit (MODU) and would not have the same operational impacts and potential risks as a MODU. BSEE is considering the effects of the size of lift boats for potential future rulemakings, and may gather additional information and provide guidance on a case-by-case basis for any lift boats comparable in size to a MODU.

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

This rulemaking would revise this section by removing many of the prescriptive real-time monitoring requirements and moving towards a more performance-based approach. BSEE would still require the ability to gather and monitor real-time well data using an independent, automatic, and continuous monitoring system capable of recording, storing, and transmitting data for the BOP control system, the well's fluid handling system on the rig, and the well's downhole conditions with the bottom hole assembly tools (if any tools are installed). Based upon BSEE's evaluation of RTM since the publication of the original WCR, BSEE determined that the prescriptive requirements for how the data is handled may be revised to allow company-specific approaches to handling the data while still receiving the benefits of RTM. BSEE is specifically soliciting comments if there are alternative ways to meet RTM provisions or if there are alternative means to meet the purposes of RTM. BSEE would completely remove existing paragraph (b) with its associated prescriptive requirements, and redesignate existing paragraph (c) as paragraph (b), with minor revisions to shift certain prescriptive elements to be more performance-based. BSEE would continue to require the items discussed in existing paragraph (c) in an RTM plan. BSEE expects operators to explain how they would carry out the requirements of the RTM plan on an individual company basis. BSEE revised this section to outline the RTM requirements and allow the operators to determine how they would fulfill those requirements.

BSEE is specifically soliciting comments about the appropriateness of utilizing RTM for workover, completion, and decommissioning operations, or whether RTM requirements should be limited to drilling operations. Please provide reasons for your position and any applicable associated data.

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

BSEE proposes to revise paragraph (a) by removing ''excluding casing shear'' and replacing ''at all times'' with ''in the event of flow due to a kick.'' Based upon BSEE experience with the implementation of the original WCR, BSEE is removing the phrase ''excluding casing shear'' because it is not necessary in this context. The requirements of this sentence are applicable to the entire BOP system, including the casing shear. BSEE expects the BOP system as a whole to be capable of closing and sealing the wellbore. BSEE also proposes to clarify that the BOP system must be able to close and seal the wellbore in the event of flow due to a kick. BSEE would make this change to codify BSEE guidance on the original WCR posted on the BSEE website at *https://www.bsee.gov/guidance-and-regulations/regulations/well-control-rule.* BSEE understands mechanical and operational design limits of equipment and expects operators to ensure ram closure time and sealing integrity before exceeding those operational and mechanical limits.

Paragraph (b) would be revised to clarify that BSEE expects the use of ''applicable'' OEM recommendations for the design, fabrication, maintenance, and repair of BOP systems, as well as personnel training in their use. The proposed revision to include ''applicable'' is necessary because some OEMs may not have specific recommendations for every item required by this paragraph. BSEE expects operators to follow OEM recommendations to the extent relevant recommendations exist.

This rulemaking would also revise the failure reporting requirements in paragraph (c) to codify BSEE guidance and current practice. The failure reporting references to American National Standards Institute (ANSI)/API Specs 6A and 16A would be removed because the failure reporting process outlined in those standards is redundant to API Standard 53 and the remaining requirements of this section. Revisions to this paragraph would include clarification on submitting failure data and reports to BSEE, unless BSEE has designated a third party to collect the data and reports, and ensuring that an investigation and failure analysis are started within 120 days. BSEE reevaluated the timeframes set forth in the original WCR regarding performing the investigation and failure analysis and determined that certain operations would not be able to meet the original timeframes. Accordingly, BSEE proposes to require that the investigation and failure analysis be started within 120 days of the failure. BSEE would then provide a 120 day timeframe to complete the investigation and failure analysis once they have started.

Based upon the unknown situations that could arise around the completion of the failure analysis and availability of the equipment, BSEE is specifically soliciting comments about whether specifying a completion date for the failure analysis is appropriate and if so whether 120 days from the commencement of the analysis is appropriate. Please provide reasons for your position and any applicable associated data.

BSEE proposes to add new paragraph (c)(4) to explain that BSEE may designate a third party to collect failure data and reports on behalf of BSEE, and failure data and reports must be sent to the designated third party. The changes regarding submittal of the reports to BSEE or designated third party would codify BSEE guidance on the original WCR posted on the BSEE website at *https://www.bsee.gov/guidance-and-regulations/regulations/well-control-rule.*

BSEE is currently using *www.SafeOCS.gov* as the designated third party. Reporting instructions are on the SafeOCS website at: *www.SafeOCS.gov*. Reports submitted through *www.SafeOCS.gov* are collected and analyzed by the Bureau of Transportation Statistics (BTS) and protected from release under the Confidential Information Protection and Statistical Efficiency Act (CIPSEA), which permits BTS to confidentially handle and store reported information.[4] Information submitted under this statute also is protected from release to other government agencies, Freedom of Information Act (FOIA) requests, and certain records requests.

BSEE also proposes to revise paragraph (d) by removing the reference to an incorrect document incorporated by reference and replacing it with the correct document incorporated by reference. The original WCR requires that BOP stacks must be manufactured pursuant to a quality management system certified by an entity that meets the requirements of ISO 17011. The correct reference is ISO 17021. This was an error in the original WCR, and BSEE would make this correction in keeping with the WCR guidance posted on the BSEE website at *https://www.bsee.gov/guidance-and-regulations/regulations/well-control-rule*

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

This rulemaking would revise the information submitted to BSEE pursuant to paragraph (a)(5) by replacing ''to achieve an effective seal of each ram BOP'' with ''to close each ram BOP.'' This revision would affect information submitted to BSEE and, based upon BSEE experience with the implementation of the original WCR, would more accurately reflect the control system and regulator control setting requirements of API Standard 53. BSEE does not expect these revisions to decrease safety. BSEE has determined that these revisions would be adequate to meet the API Standard 53 requirements for control systems to ensure that each ram BOP can be effectively sealed, as the original WCR language intended.

This section would also be revised by removing the BAVO verification requirements in existing paragraphs (d) and (f). The BAVO verifications required by existing paragraphs (d)(1) and (d)(3) were redundant to the verifications required by paragraph (c); however, the verifications required by current paragraph (d)(2) are still necessary and BSEE therefore proposes to add them to revised paragraph (c). BSEE proposes to remove paragraph (f) because the Report that is the subject of that paragraph is proposed for elimination in connection with proposed revisions to § 250.732(d) (see section-by-section discussion of that provision for further explanation). The independent third party verifications under paragraph (c) help ensure that the BOP is fit for service at each specific well. BSEE proposes to revise this section by replacing references to a BAVO with references to an independent third party that meets the requirements of § 250.732(b). For a discussion of the proposed shift from BAVOs to independent third parties, see the section-by-section discussion of § 250.732.

What are the independent third party requirements for BOP systems and system components? (§ 250.732)

BSEE proposes to completely revise this section by removing all references to a BAVO and, where appropriate, replacing those references with an independent third party. This change would also be made in appropriate locations throughout subpart G where BAVOs are referenced, as noted throughout the applicable section-by-section discussions. This change would not impact safety because independent third parties have been utilized as a long-standing industry practice to carry out certifications and verifications similar to those which a BAVO would do. BSEE expected most of the companies or individuals currently being used as independent third parties to apply to become a BAVO. Since the publication of the original WCR, BSEE has increased its interaction with the independent third parties to better understand how they operate and carry out certifications and verifications. BSEE has determined that, if as expected the majority of BAVOs would be drawn from the existing independent third parties who would continue to conduct the same verifications, additional BSEE oversight and submittal to become a BAVO would be unnecessary and the BAVO system implemented by the WCR would increase procedural burdens and costs without giving rise to meaningful improvements to safety or environmental protection. If BSEE becomes aware of any performance issues with an independent third party, there are still options for BSEE to address the issues (*e.g.,* through a SEMS audit, or verifications through the permitting process). Based upon the BSEE determination to remove the BAVOs, BSEE would revise the section heading to reflect the change from a BAVO to an independent third party, remove paragraphs (a)(1) and (a)(3), and replace all remaining BAVO references with references to an independent third party. The independent third party qualifications in existing paragraph (a)(2) would remain in this section as new paragraph (b).

This proposed rule would remove the requirements to verify that testing was performed on the outermost edges of the shearing blades of the shear ram positioning mechanism, found in current paragraph (b)(1)(iv). This would align the verification requirements with BSEE's proposal to remove the centering mechanism required in existing § 250.734(a)(16) that is the subject of this verification (see section-by-section discussion of § 250.734 for discussion of those changes). BSEE does not expect this revision to decrease safety since it simply aligns this testing requirement with the proposed change to § 250.734(a)(16). As explained in connection with that proposed change, BSEE believes that, since newer shearing blades can center pipe, it is unnecessary to require a pipe centering mechanism. In addition, the shear rams are capable of shearing along the entire blade surface area without specifically requiring testing on the outermost edges. BSEE also proposes to remove from existing paragraph (b)(1)(i) a vestigial reference to a compliance deadline that has already passed. This is merely an administrative revision.

BSEE would also revise existing paragraph (b)(2)(ii) to proposed paragraph (a)(2)(ii) by changing the testing facilities' verification pressure testing hold time demonstration from 30 minutes to 5 minutes. This revision would allow the continued use of the established historical data to help verify the pressure holding time. BSEE is proposing to revise this paragraph after consideration and reevaluation of the original WCR and historical data along with the longstanding successful practical application of that data. BSEE does not expect this revision to decrease safety because the shear ram testing timeframes of five minutes in a lab have been well established, and BSEE believes the historical data indicates that five minutes is adequate to demonstrate effective sealing. BSEE has increased its interaction with testing facilities and is continuing to evaluate any additional testing protocols. BSEE will continue to interact with testing facilities to ensure that new protocols or test data do not show a need for a longer test period.

BSEE also proposes to make a minor revision to paragraph (c) to update an incorrect citation—the referenced definition of High Pressure High Temperature (HPHT) environments is found in § 250.804(b) rather than § 250.807(b), as stated in the current regulations. This revision is administrative in nature and ensures

[4] OMB defines BTS as one of 14 CIPSEA statistical agencies; BSEE is not a CIPSEA statistical agency. (''Implementation Guidance for [CIPSEA]''); 72 FR 33362 at 33368 (June 15, 2007).

that the appropriate citations are correctly cross referenced.

With the removal of the BAVO references, BSEE is also proposing to remove the mechanical integrity assessment (MIA) report requirements from paragraph (d). This MIA report was a function of the BAVO. Based on discussions regarding the MIA report after publication of the original WCR, BSEE determined that the information contained within the MIA report was redundant with the BOP equipment capability verifications required by § 250.731. The independent third party verifications in § 250.731 help ensure that the BOP systems have the appropriate capabilities and are fit for service for a specific well and location.

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

This rulemaking would revise paragraph (a)(1) by removing the reference to an extended time for compliance with exterior control line shearing requirements under the original WCR, which BSEE anticipates will have run and no longer warrant reference in the regulations by the time a final rule is promulgated. BSEE also proposes to remove the requirement to have an alternative cutting device used for shearing electric-, wire-, or slick-line if your blind shear rams are unable to cut and seal under maximum anticipated surface pressure (MASP). The alternative cutting device is no longer necessary because the currently commercially available shear rams have increased design capabilities, which are capable of shearing these types of lines. BSEE is aware of concerns regarding the removal of the alternative cutting device option. Therefore, BSEE is considering other options in the final rule, such as keeping the alternative cutting device provisions in the regulations or extending the compliance date to allow the use of the alternative cutting devices until a more appropriate date when the surface stack shear rams can be upgraded to shear electric-, wire-, or slick-line.

BSEE is specifically soliciting comments about the effectiveness of using an alternative cutting device and whether BSEE should continue to allow its use. Additionally, BSEE is also specifically soliciting comments on how long it would take for surface stack shear rams to be upgraded to shear electric-, wire-, or slick-line. Please provide reasons for your position and any applicable associated data.

BSEE is also proposing to revise paragraph (b)(1) to extend the compliance date from April 29, 2019 to April 29, 2021, to correspond with the same requirements for subsea BOP stacks. This revision would align the dual shear ram requirements for surface BOPs installed on floating facilities and subsea BOPs. Aligning these dates would help minimize confusion between the conflicting effective dates of the parallel requirements for surface BOPs used on floating facilities and subsea BOPs. This revision would also allow more time to install the dual shear rams in a surface BOP on a new floating facility and potentially minimize the technical and economic challenges prior to installation.

New paragraph (e) would be added to clarify the minimum surface BOP system requirements for well-completion, workover, and decommissioning operations where estimated well pressures are low. The provisions in this proposed paragraph were inadvertently removed from the regulations through the original WCR and are consolidated from §§ 250.516, 250.616, and 250.1706 of the regulations as they existed before the original WCR. BSEE is proposing minor revisions to the original language to conform to the applicable operations covered under revised Subpart G and to update cross-referenced citations. When BSEE developed the original WCR, it attempted to consolidate all of the BOP requirements from Subparts D, E, F, and Q, but in doing so inadvertently removed the requirements of this paragraph. The provisions in this paragraph would provide flexibility to utilize appropriate configurations and capabilities for surface BOP stacks where estimated well pressures are low (*e.g.,* an end of life well).

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

BSEE proposes to revise paragraph (a)(1)(ii) by clarifying that a ''combination of the'' shear rams must be capable of shearing all the items specified in the paragraph. This revision would better align the functionality of the BOP system with API Standard 53 and proposed § 250.730(a). Based upon BSEE experience with the implementation of the original WCR, BSEE is aware that certain casing shears still have difficulty shearing electric-, wire-, or slick-line, while certain blind shear rams have difficulties shearing larger casing sizes. This proposed revision would provide the operators flexibility for how they utilize the BOP system and components for operations while still ensuring all critical shearing capabilities. This would not impact safety because BSEE would still require the capability to shear at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies such as heavy-weight pipe or collars), workstring, tubing and associated exterior control lines, appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric-, wire-, slick-line in the hole. BSEE expects the operators to better evaluate how the BOP system, including both shear rams, would function together to comply with the required shearing capabilities. The proposed rule would also revise paragraph (a)(1)(ii) by removing references to extended times for compliance with certain shearing requirements under the original WCR, which BSEE anticipates will have run and no longer warrant reference in the regulations by the time a final rule is promulgated.

This rulemaking would revise the accumulator requirements in paragraph (a)(3) to better align with API Standard 53. BSEE would remove the reference to the subsea location of the accumulator capacity. BSEE understands that the accumulator system works together with the surface and subsea accumulator capacity to achieve full functionality, and BSEE determined that it was unnecessary to specifically identify only subsea requirements when the entire system is covered within API Standard 53. BSEE does not expect these revisions to reduce safety. The requirements to operate the key components of the BOP subsea will remain the same. This revision helps reduce the non-critical accumulator capacity on the BOP stack subsea, but would not affect safety of the critical components. Adding subsea accumulator bottles increases weight and size, which could have a negative impact on the stability and functionality of existing facilities by exceeding the operational or mechanical design limits of the wellhead and BOP systems.

Paragraph (a)(3)(i) would be revised by clarifying that the accumulator capacity must be sufficient to close each required shear ram, ram locks, one pipe ram, and disconnect the LMRP. During a well control event, the most critical functions would be to close the BOP components and seal the well. This revision would also align the requirements with the intent of the API Standard 53 request for information finalized after the original WCR.

Paragraph (a)(3)(ii) would be revised to clarify that the accumulator capacity must have the capability to perform the ROV functions within the required times outlined in API Standard 53 with ROVs or flying leads. Based upon BSEE experience with the implementation of the original WCR, BSEE is proposing to revise this paragraph not only to better align with API Standard 53, but also to account for the technological advancements in ROV capabilities and ROV standardization to meet the appropriate BOP closing times via an ROV. Many of these advancements have taken place after publication of the original WCR. BSEE is aware of operators currently using high flow rate ROVs to meet the BOP component closing times of API Standard 53.

Paragraph (a)(3)(iii) would be revised by removing the mention of ''dedicated'' bottles and allowing bottles to be shared among emergency and secondary control system functions to secure the wellbore. This revision would further align the accumulator capacity requirements with API Standard 53 and account for the appropriate number of accumulator bottles on the subsea BOP stack. This revision would increase operator flexibility to utilize the appropriate accumulator capacity to perform the necessary emergency functions. Through the implementation of the original WCR, BSEE was able to better evaluate the effects of the original WCR accumulator requirements impacting subsea BOP space and weight limitations. This revision would help ensure that the regulatory requirements do not exceed the operational or mechanical design limits of the wellhead and BOP systems, and would help minimize risks associated with approaching those design limits.

This rulemaking would revise paragraph (a)(4) by removing the term ''opening'' and adding reference to the ROV function response times outlined in API Standard 53. After publication of the original WCR, the API Standard 53 committee clarified the definition of ''operate'' critical functions to include ''close'' only and not to include ''open.'' Removal of the ROV open function would limit the ability for well intervention after the well has already been secured; however, it would not affect or decrease the ability for the ROV to close the required components for well control purposes. During a well control event, the most critical functions would be to close the BOP components and seal the well. This revision would minimize the required number of equipment alterations to the subsea ROV panel and associated control systems and improve consistency with similar requirements in API Standard 53. The open function on the ROV panel may also be unnecessary due to technological advancements in well intervention capabilities once the well has already been secured. This paragraph would also be revised by requiring the ROV to function the appropriate BOP component within the required response time outlined in API Standard 53. BSEE is proposing to revise this paragraph not only to better align with API Standard 53, but also to account for the recent technological advancements in ROV capabilities and ROV standardization to meet the appropriate BOP closing times via an ROV. BSEE is aware that operators currently use high flow rate ROVs to meet the BOP component closing times of API Standard 53.

BSEE would also update the incorporated reference to API RP 17H to a newer edition in § 250.198(h)(94). There is a conflict between the API RP 17H first edition referenced in the original WCR and the API Standard 53 ROV requirements. The second edition of API RP 17H eliminates the conflict between the first edition and API Standard 53. BSEE would incorporate by reference the second edition of API RP 17H to ensure the appropriate methods are utilized to comply with the API Standard 53 ROV closure timeframes of 45 seconds. One of the main differences between the first edition and second edition of this recommended practice is that the second edition includes provisions on high flow Type D 17H hot stabs.

This rulemaking would also revise paragraph (a)(6)(iv) by clarifying that the autoshear/deadman functions must close at a minimum two shear rams in sequence, not every emergency function. Closing two shear rams in sequence may not be advantageous for certain emergency disconnect system (EDS) functions. Depending upon the rig operations, operators develop different EDS modes that would function different BOP components at appropriate times. The selection of the EDS mode and the specific sequencing of emergency functions should be developed by the operator based on safety considerations and an operational risk assessment. BSEE would make this change to codify BSEE guidance on the original WCR posted on the BSEE website at *https://www.bsee.gov/guidance-and-regulations/regulations/well-control-rule.*

BSEE would revise paragraph (a)(16) by removing references to the centering mechanism and the ability to mitigate compression of the pipe between the shear rams in paragraphs (i) and (ii), respectively. Based upon BSEE experience with the implementation of the original WCR and increased interactions with OEMs of shearing components, BSEE would remove these paragraphs based upon a better understanding of the technological advancements of available shearing capabilities to accomplish the same goals outlined in these paragraphs. Many of the shear ram designs have improved the shearing capabilities to help ensure the shearing is conducted on the appropriate shearing area of the shear blades. This is commonly done by shaping the shear ram cutting blades in a ''V'' or ''W'' pattern to help center the pipe as it shears, as well as to increase the blade face surface area to ensure there are no areas that cannot shear the pipe in the well. BSEE is also proposing to remove paragraphs (a)(6)(v) and (a)(6)(vi) based upon a better understanding of the third party verifications and documentation of the shearing requirements as outlined in current § 250.732(b). BSEE does not expect these revisions to decrease safety because these newer designed shear rams are off the shelf available components that can be swapped with current components. BSEE believes that operators will continue to substitute new components for old ones to comply with the still-required increased shearing capability provisions of the original WCR. BSEE is aware of many technological advancements in shearing ram designs and capabilities. BSEE expects the shear rams to shear pipe or wire in any position within the wellbore; however, BSEE is specifically soliciting comments about the effectiveness of requiring shear rams to center pipe or wire while shearing, or requiring shear rams to have the capability to shear any pipe or wire in the hole without a separate centering mechanism. Another option BSEE is considering is retaining the centering mechanism requirements, but expressly providing that the shear rams with these capabilities satisfy the requirements. Please provide reasons for your position and any applicable associated data.

This rulemaking would revise paragraph (b)(1) by replacing the BAVO references with references to an independent third party. For a discussion of the general shift from BAVOs to independent third parties, see the section-by-section discussion of § 250.732.

BSEE would also revise paragraph (b)(2), redesignate existing paragraph (b)(3) as (b)(4), and add new paragraph (b)(3) to include provisions for testing the applicable BOP or LMRP upon relatch to the well. The original WCR did not address this provision, however based upon BSEE experience, these revisions would codify longstanding BSEE policy and provide clarity for testing when an operator has returned to the location and relatched the BOP or LMRP to the well. These tests help confirm that the BOP or LMRP is properly functional prior to resuming operations after being removed.

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

This proposed rule would revise paragraph (a) by clarifying that the accumulator system must have the fluid volume capacity and appropriate pre-charge pressures in accordance with API Standard 53. BSEE would revise this section to provide consistency with the API Standard 53 and conform to the other proposed accumulator system revisions in § 250.734. This revision would not materially alter the requirements of this section, which are already based upon API Standard 53. An accumulator system is necessary to provide the fluid and pressure to operate desired BOP functions. API Standard 53 outlines the pre-charge pressure calculations in Annex C and additional requirements for the accumulator system pressures in the drawdown tests.

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

This rulemaking would revise paragraph (d)(5) by including equipment requirements for the safety valve when running casing with a subsea BOP. This revision would specify that the safety valve must be available on the rig floor if the length of casing being run exceeds the water depth, which would result in the casing being across the BOP stack and the rig floor prior to crossing over to the drill pipe running string. Based upon BSEE experience with the implementation of the original WCR, the substance of this revision is currently incorporated into every subsea well permit approval as a standard condition. This revision would provide clarity and consistency throughout BSEE permitting and minimize the number of alternate procedure or equipment requests submitted to BSEE.

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

This rulemaking would revise paragraph (b) to clarify the BOP system pressure testing requirements. These revisions would include clarification that the test rams and non-sealing shear rams do not need to be pressure tested, and this would not impact safety because the non-sealing shear rams are not pressure holding components and the test ram is an inverted ram that is not utilized for well control purposes. Paragraph (b)(2) would be revised to add in the current BSEE policy for conducting the high-pressure test for specific components. For example, some of the revisions would include specific procedures and testing parameters for initial equipment pressure testing and also include the provisions for subsequent pressure testing on the same equipment. Since the publication of the original WCR, BSEE received many questions from operators regarding the operational application of the current pressure testing requirements. This proposed revision would codify BSEE policy and provide clarity and consistency for permitting throughout the Regions and Districts.

In this proposed rule, BSEE would also revise paragraphs (d)(2) and (d)(3) by removing the requirement to submit test results to BSEE where BSEE is unable to witness testing. Based upon BSEE experience with the implementation of the original WCR, these revisions would significantly reduce the number of submittals to BSEE and minimize the associated burden for BSEE to review those submittals. If BSEE is unable to witness the testing, BSEE still has access to the testing documentation upon request in accordance with §§ 250.740, 250.741, and 250.746.

Paragraph (d)(3)(iv) would be revised by removing ''test and[.]'' BSEE would remove this term to minimize confusion regarding verification and testing. In this instance, verification of closure qualifies as testing the ROV functions. The purpose of the stump test is to help ensure the BOP components and control systems can function properly before being utilized on a well.

BSEE would revise paragraph (d)(3)(v) to clarify that pressure testing of each ram and annular on the stump test is only required once. This revision would help ensure that the testing of BOP components during stump testing would limit unnecessarily duplicative pressure testing on each ram or annular. BSEE would also make this change to codify BSEE guidance on the original WCR. The purpose of the stump test is to help ensure the BOP components and control systems can function properly before being utilized on a well. It is unnecessary to pressure test a ram or annular multiple times during stump testing if that component has already been successfully pressure tested, verifying proper functionality. This revision would help limit the risk associated with component wear.

Paragraph (d)(4)(i) would be revised to clarify that the initial subsea BOP test on the sea floor would need to ''begin'' within 30 days of the stump test. BSEE receives many questions about the timing of the initial subsea test and, as written, the regulation was ambiguous regarding exactly what needed to occur within the 30 days. Based upon its experience with the implementation of the original WCR, BSEE proposes this revision to clarify that the testing has to begin within 30 days. BSEE wants to ensure that the time between the stump testing and the initial subsea test is minimal to help ensure that all of the BOP components can properly function upon installation on the well.

Paragraph (d)(4)(iii) would be revised to include annulars in the pressure testing requirements of paragraphs (b) and (c) of this section. This revision would not alter the current testing requirements for annulars, but based upon BSEE experience with the implementation of the original WCR, would provide clarity for where to find them.

Paragraph (d)(4)(v) would be revised to clarify the initial subsea pressure testing requirements to confirm closure of the selected ram through an ROV hot stab. This revision would require the operator to confirm closure through a 1,000 psi pressure test held for 5 minutes. This revision would codify BSEE policy for pressure testing the selected ram through the ROV hot stabs. Based on BSEE experience during the implementation of the original WCR, BSEE has concluded that testing to higher pressures is not necessary for this circumstance because the intended purpose of this test is to verify operability of the ROV hot stab to close the selected ram. Selected rams will be pressure tested according to other regularly required pressure testing intervals. This revision would save rig operational time by reducing the amount of time required to conduct the pressure test, minimize the risk associated with wear of the BOP components, and eliminate associated alternate procedure requests.

Existing paragraph (d)(4)(vi) would be removed because the testing requirements of the selected ram would now be covered under proposed paragraph (d)(4)(v).

BSEE would revise paragraph (d)(5) by clarifying the alternating testing schedules of control stations and pods. These revisions would ensure that operators develop a testing schedule that allows for alternating testing between the control stations, and also between the pods for subsea BOPs. The intended result of alternating the testing is to ensure that each control station, and each pod for subsea, can properly function all required BOP components. Based on BSEE experience during the implementation of the original WCR, BSEE has concluded that these revisions would help ensure BOP functionality while not inadvertently requiring unnecessarily duplicative testing. This revision would save rig operational time by reducing the number of unnecessary duplicate tests, and minimize the risk associated with wear of the BOP components functioned during testing.

Paragraph (d)(12)(iv) would be revised by clarifying that, during the deadman test on the seafloor, operators are not required to indicate the discharge pressure of the subsea accumulator throughout the entire test. These revisions would require that the remaining pressure be documented at the end of the test, to help verify the proper accumulator settings required to function the specific critical BOP components.

Paragraph (d)(12)(vi) would be revised to clarify the pressure testing requirements of the original WCR, to confirm closure of the BSR(s) during the autoshear/deadman and EDS testing. This revision would require confirmation of closure through a 1,000 psi pressure test held for 5 minutes. Based upon BSEE experience with the implementation of the original WCR, this revision would codify BSEE policy for autoshear/deadman and EDS pressure testing of the BSR(s). Testing to higher pressures is not necessary for this circumstance because the BSR(s) will be pressure tested according to other regularly required pressure testing intervals. This revision would save rig operational time by reducing the amount of time required to conduct the pressure test, and minimize the risk associated with wear of the BOP components.

BSEE proposes to add paragraph (d)(13) setting forth exceptions for pressure testing the choke and kill side outlet valves. Since publication of the original WCR, BSEE has received many questions from operators regarding the operational application of the current pressure testing requirements. This addition would codify BSEE policy and provide consistency for permitting throughout the Regions and Districts without meaningfully reducing safety or environmental protection.

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

This rulemaking would revise paragraphs (b), (i), (m), and (o) by replacing the references to BAVOs with references to an independent third party throughout. For a discussion of the proposed shift from BAVOs to independent third parties, see the section-by-section discussion of § 250.732.

Paragraph (f) would be revised to clarify the testing requirements implemented by the original WCR necessary to verify the integrity of the affected casing ram or casing shear ram and connections. Based upon BSEE experience with the implementation of the original WCR, this revision would codify BSEE policy to allow the pressure testing to the test pressure of the BOP component above this ram as specified in the approved permit.

Paragraph (m) would be revised to replace the term ''well-control equipment'' with ''circulating or ancillary equipment.'' This revision would eliminate confusion arising from the use of conflicting terms that may have different meanings throughout the regulations.

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

BSEE proposes to revise paragraph (b) by replacing ''complete breakdown and detailed physical inspection'' with a ''major, detailed inspection,'' identifying examples of well control system components, replacing references to the BAVO with references to an independent third party, and replacing the requirement to have a BAVO present during each inspection with a requirement for an independent third party to review inspection results.

Replacing ''complete breakdown and detailed physical inspection'' with a ''major, detailed inspection'' would correct the industry misconception, prevalent since the promulgation of the original WCR, that each component must be dismantled to its smallest possible part. This was never the intent behind this provision of the WCR, and these revisions would clarify BSEE's positions on the WCR requirement and resolve perceived ambiguities, without substantively altering the inspection requirement. BSEE would make this change to codify BSEE guidance on the original WCR posted on the BSEE website at *https://www.bsee.gov/guidance-and-regulations/regulations/well-control-rule.* BSEE also proposes to add references to examples of the well control system components requiring inspection to clarify the general reference in the original WCR.

For a discussion of the proposed shift from BAVOs to independent third parties, see the section-by-section discussion of § 250.732.

BSEE would also remove the requirement for the BAVO to be present during each inspection and replace it with a requirement that an independent third party review the inspections results. BSEE expects the independent third party to review the documentation of the inspections to help ensure that the appropriate entities accurately and appropriately complete the activities. These reports would also help facilitate other required verifications that the BOP is fit for service, such as those required by § 250.731. These revisions would ease the original WCR logistical and economic burdens of having the BAVO onsite at all times during all inspections.

What are the coiled tubing and snubbing requirements? (§ 250.750)

The content of this proposed section was moved from current §§ 250.616 and 250.1706. This section would consolidate some of the minimum BOP system component requirements for coiled tubing and snubbing operations. BSEE is proposing minor revisions to the original language to conform to the applicable operations covered under Subpart G. BSEE is also proposing to add paragraph (d) to conform snubbing unit testing with updated requirements.

Coiled Tubing Testing Requirements (§ 250.751)

BSEE proposes to add this section to codify current BSEE policy regarding the coiled tubing testing and recording requirements. This addition would a reintroduce similar provisions that were inadvertently removed in the original WCR, consolidating elements from §§ 250.617 and 250.1707 of the regulations as they existed before the original WCR. Both sections are currently reserved. BSEE is proposing revisions to the original language to conform to the applicable requirements of Subpart G. For example, BSEE would not include in this section the provisions regarding testing of the coiled tubing connector, because the proposal would require that operators ''must test the coiled tubing unit in accordance with § 250.737 paragraphs (a), (b), (c), (d)(9), and (d)(10)''. Section 250.737 requires testing of the system when installed and provides testing criteria. Identifying the connector testing in this section is not necessary because it is already covered by the testing requirements of § 250.737.

Subpart Q—Decommissioning Activities

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

This rulemaking would revise paragraph (b) to clarify that only packers or bridge plugs used as mechanical barriers are required to comply with ANSI/API Spec. 11D1. Based upon BSEE experience with the implementation of the original WCR, this revision would codify BSEE's policy to ensure that the required mechanical barriers in a well are held to a higher standard than other common packers or bridge plugs used for various well specific conditions and completions design. Furthermore, BSEE is aware that certain packers and bridge plugs cannot meet the specifications of ANSI/API Spec. 11D1. This revision would minimize the number of alternate equipment requests submitted to BSEE. BSEE would also add that operators must have two independent barriers, one being mechanical, in the exposed center wellbore (*e.g.,* this could be the tubing or casing depending on the well configuration) prior to removing the tree or well control equipment. This addition would codify BSEE policy and align the well decommissioning requirements with similar requirements from §§ 250.720(a) and 250.1712(g). This addition would help ensure the well is properly secured before removal of the tree or well control equipment.

What decommissioning applications and reports must I submit and when must I submit them? (§ 250.1704)

BSEE proposes to revise paragraph (g) by adding the requirements for submittal of the site clearance verification activity information in an Application for Permit to Modify (APM). The site clearance verification activity information would be removed from the end of operations report (EOR). Based on BSEE experience during the implementation of the original WCR, BSEE became aware of dual reporting of the same information and confusion about which permit or report should include the information. These revisions would better reflect current practice and limit redundant reporting.

Paragraph (h) would be revised by adding the submittal of the decommissioning activity information, upon completion, in the EOR. Based upon BSEE experience with the implementation of the original WCR, these revisions would better reflect current practice and limit redundant reporting.

Coiled Tubing and Snubbing Operations (§ 250.1706)

This section would be removed and reserved. The content of this section would be moved to proposed § 250.750. These revisions would help BSEE eliminate inconsistencies between similar requirements throughout different BSEE subparts by consolidating those requirements into Subpart G, which is applicable to drilling, completions, workovers, and decommissioning operations.

Must I notify BSEE before I begin well plugging operations? (§ 250.1713)

This section would be removed and reserved. Based upon BSEE experience with the implementation of the original WCR, BSEE determined that the submittal of the information required by this section is redundant with similar rig movement notification information required under § 250.712.

To what depth must I remove wellheads and casings? (§ 250.1716)

This rulemaking would revise paragraph (b)(3) by changing the water depth criteria for when BSEE may approve an alternate depth for removal of the wellhead or casing from 800 meters to 1000 feet. BSEE would include this new regulatory revision in order to codify longstanding BSEE policy established before the original WCR. At depths below 1,000 feet, there is little risk of obstruction to other users of the OCS or its waters or contact with other equipment, and little risk of safety or environmental issues from removal to an alternate depth.

If I install a subsea protective device, what requirements must I meet? (§ 250.1722)

BSEE proposes to revise paragraph (d) to direct the submittal of the trawl test report to the EOR rather than an APM. This revision would reflect current BSEE practice established before publication of the original WCR and help minimize redundant reporting. It would not affect the substance of the reporting requirement or the information BSEE receives, only the mechanism through which it is received.

III. Additional Comments Solicited

A. BOP Testing Frequency

BSEE is requesting comments on whether the BOP testing interval should be 7 days, 14 days, or 21 days for all types of operations including drilling, completions, workovers, and decommissioning. BSEE is also requesting comments on the specific cost and operational implications of each testing interval to further its consideration of the issue.

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 the benefits of pressure and functional testing of subsea BOPs when compared to the costs and potential operational issues. 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? BSEE is aware of potential technologies that may improve the operability and reliability of BOP systems. 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?

Please provide supporting reasons and data for your responses.

B. Economic Data

The compliance costs and savings in the regulatory impact analysis (RIA) are BSEE's best estimates based on experience with the previous WCR, stakeholder comments, and communication with industry. BSEE is requesting comments related to the appropriateness and accuracy of the compliance costs and benefits identified in the RIA. Please provide supporting reasons and data for your responses.

IV. Procedural Matters

Regulatory Planning and Review (Executive Orders (E.O.) 12866, 13563, and 13771)

Executive Order 12866 provides that the Office of Information and Regulatory Affairs within the OMB will review all significant rules. BSEE coordinated development of an economic analysis to assess the anticipated costs and potential benefits of the proposed rulemaking. OIRA has determined that it would have a positive annual effect on the economy of $100 million or more. The significant positive economic effect on the economy is the result of the proposed cost savings in this rule. BSEE estimates the amendments in this rulemaking would save the regulated industry $98.6 million annually over ten years (discounted at 7 percent).

Executive Order 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. Executive Order 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. We have developed this rule in a manner consistent with these requirements.

Executive Order 13771 requires Federal agencies to take proactive measures to reduce the costs associated with complying with Federal regulations. This proposed rule is expected to be an E.O. 13771 deregulatory action. Details on the estimated cost savings of this proposed rule can be found in the rule's economic analysis. The cost savings for the regulatory clarifications, reduction in paperwork burdens, adoption of industry standards, and migration to performance-based standards for select provisions constitute an E.O. 13771 deregulatory action. BSEE also finds that the reduced regulated entity compliance burden would not increase the safety or environmental risks for offshore drilling operations.

This rulemaking proposes to revise regulatory provisions in 30 CFR part 250, subparts D, E, F, G, and Q. BSEE has reassessed a number of the provisions in the original (1014–AA11) WCR rulemaking and proposes to rewrite some provisions as performance-based standards rather than prescriptive requirements. Other proposed revisions would reduce or eliminate parts of the paperwork burden, while providing the same levels of safety and environmental protection. BSEE sought the best available data and information to analyze the economic impact of the proposed changes. The Initial RIA (IRIA) for this rulemaking can be found in the *https://www.regulations.gov/* docket (Docket ID: BSEE–2018–0002). The IRIA indicates that the estimated overall cost savings to the industry over the next 10 years would exceed $900 million in nominal dollars.

BSEE proposes to revise certain provisions of the original rule to support the goals of the regulatory reform initiatives while ensuring safety and environmental protection. BSEE has received additional information since the publication of 1014–AA11 and revisited several of the compliance cost assumptions in the economic analysis for the 2016 1014–AA11 final rule. The proposed modifications to the BSEE compliance cost estimates in the 1014–AA11 analysis are primarily related to:

(1.) Underestimating the cost for revising permits or reporting certain operations to the District Manager (§§ 250.428 and 250.722), and

(2.) Underestimating both the number of subsea BOPs that would require modifications and the cost of those modifications under the 1014–AA11 regulations (§ 250.734).

The proposed revisions to existing ram and accumulator requirements for subsea BOPs (§ 250.734) represent the single largest cost savings provision in this proposed rule, yielding cost savings of $690 million (nominal$). The proposed changes to § 250.734 would better align the shear ram provisions with API Standard 53, revise the accumulator capacity requirements for subsea BOP stacks, and redefine shearing requirements.

BSEE expects the proposed rule would reduce the regulatory burden on industry, and the proposed amendments would not negatively impact worker safety or the environment. BSEE proposes to provide industry flexibility, when practical, to meet the safety or equipment standards, rather than specifying the compliance method. For example, BSEE is proposing to eliminate the requirement that operators resubmit an Application for Permit to Drill (APD) in the event of planned mud losses or inadequate cement jobs. Instead, BSEE proposes to allow the operator to outline remedial actions to these scenarios in contingency plans included in the original approved APD. This revision would not change the operational responses to these events, and therefore will reduce the paperwork burden and expensive operational downtime without increasing drilling risks. Other changes would remove BOP stack certification requirements regarding design specifications and equipment conditions and replace the BAVO requirements for BOP systems and system components with independent third party requirements. The existing provisions are either duplicative or provide a more burdensome certification process than necessary. The proposed changes to the certification processes will continue to protect worker safety and the environment.

The proposed § 250.734 amendments would better define the BOP components functionality requirements, revise the requirements for ROV capability and functionality, and amend accumulator capacity requirements for subsea BOP stacks. This revision to the accumulator requirements would increase operator flexibility to utilize the appropriate accumulator capacity to perform the necessary emergency functions. Through the implementation of the original WCR, BSEE was able to better evaluate the effects of the original WCR accumulator requirements on subsea BOP space and weight limitations. After reevaluating the API 53 standards, BSEE agrees that certain prescriptive requirements in the current regulations are unnecessary and the proposed regulatory text revisions would align BSEE regulations with the performance standards in API Standard 53. The proposed § 250.734 revisions would also remove the prescriptive requirement that EDS emergency functions must close at a minimum two shear rams in sequence. This would allow the operator to select the appropriate EDS emergency function shearing sequence for the circumstances and would adopt the performance standard that the BOP system must be able to seal the wellbore. Furthermore, the accumulator capacity required in API 53 is sufficient to actuate the BOP ram functions necessary to seal the well. This performance standard meets the intent of the 1014–AA11 well control rule without the prescriptive and unnecessarily burdensome requirements. The alignment of the accumulator volume requirements with industry standards would also provide additional safety benefits. The weight of the combined BOP and accumulator bottle package required by the original rule would be reduced with these proposed revisions. This reduction would avoid increased strain on rig handling systems and potentially avoid modifications on some rigs to accommodate the additional space and BOP handling requirements.

The proposed § 250.737 paragraph (d)(5) amendments would allow the operator to alternate tests between the two control stations rather than testing from both control stations on each test. Testing from both control stations on a weekly basis has been proven to wear the BOP components out at a faster rate than was expected when the original WCR was written. The proposed rule would return the regulations to pre-1014–AA11 regulatory language in order to prevent the additional wear and tear on the BOP components. This change would align BSEE regulations with the industry testing standards.

BSEE's estimate of the net total, annualized and discounted regulatory cost savings can be found in the following table.

Total Estimated Cost Savings Associated with Proposed Amendments to Subparts D, E, F, G, and Q

Year	Undiscounted	Discounted at 3%	Discounted at 7%
Total	$946,175,915	$824,163,783	$692,766,029
Annualized	$94,617,592	$96,617,138	$98,634,297

This rulemaking would reduce the burden imposed on society while ensuring continued safety and environmental protection. Additional information on the compliance costs, savings, and benefits can be found in the IRIA posted in the docket.

BSEE has developed this proposed rule consistent with the requirements of E.O. 12866, E.O. 13563, and E.O. 13771. This proposed rule would revise multiple provisions in the current regulations with performance-based provisions based upon the best reasonably obtainable safety, technical, economic, and other information. Other redundant or unnecessary reporting requirements are proposed for elimination. BSEE proposes to provide industry flexibility, when practical, to meet the safety or equipment standards, rather than specifying the compliance method. Based on a consideration of the qualitative and quantitative safety and environmental factors related to the proposed rule, BSEE's assessment is that its promulgation would be consistent with the requirements of the applicable Executive Orders and the OCSLA.

Regulatory Flexibility Act and Small Business Regulatory Enforcement Fairness Act

The Regulatory Flexibility Act, 5 U.S.C. 601–612, requires agencies to analyze the economic impact of proposed regulations when a significant economic impact on a substantial number of small entities is likely and to consider regulatory alternatives that will achieve the agency's goals while minimizing the burden on small entities. In addition, the Small Business Regulatory Enforcement Fairness Act of 1996, 5 U.S.C. 601 note, requires agencies to produce compliance guidance for small entities if the rule has a significant economic impact. For the reasons explained in this analysis, BSEE believes the proposed rule may have a significant economic impact and, therefore, a regulatory flexibility analysis for the Proposed Rule is required by the RFA. The Initial Regulatory Flexibility Analysis (IRFA), which assesses the impact of this proposed rule on small entities, can be found in the Regulatory Impact Analysis (RIA) within the docket for this rulemaking.

As defined by the Small Business Administration (SBA), a small entity is one that is ''independently owned and operated and which is not dominant in its field of operation.'' What characterizes a small business varies from industry to industry in order to properly reflect industry size differences. This proposed rule would affect lease operators that are conducting OCS drilling or well operations. BSEE's analysis shows this could include about 69 companies with active drilling or well operations. Of the 69 companies, 21 (30 percent) are large and 48 (70 percent) are small. Entities that would operate under this proposed rule are classified primarily under North American Industry Classification System (NAICS) codes 211120 (Crude Petroleum Extraction), 211130 (Natural Gas Extraction), and 213111 (Drilling Oil and Gas Wells). The proposed rule would indirectly impact OCS drilling companies that are the regulated entities classified under NAICS code 21311 and this analysis focuses on the OCS oil and gas lessees and operators. For NAICS codes 211120, SBA defines a small company as having fewer than 1,251 employees.

BSEE considers that a rule will have 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. BSEE's analysis shows that there are 48 small companies with active operations on the OCS, and all of these companies could be impacted by the proposed rule if conducting drilling or well operations. Therefore, BSEE expects that the proposed rule would affect a substantial number of small entities.

Large companies are responsible for the majority of activity in deepwater, where subsea BOPs are used with floating MODUs. BSEE's first-order estimate for the rulemaking's small entity cost savings is proportional to the number of drilling rigs being operated or contracted by small companies (circa October 2017).

This proposed rule is a deregulatory action; however, BSEE has evaluated possible costs and benefits and has estimated that there is an overall associated cost savings. BSEE has estimated the annualized cost savings by regulatory provision and then allocated those savings to small or large entities based on drilling/well activity (circa October, 2017; activity breakouts can be found in the IRFA). The proposed changes to §§ 250.423, 250.734, and 250.737 paragraph (d)(5) would only apply to subsea BOPs and would yield cost savings that sum to $70,250,336. All remaining proposed changes would apply to all well operations or subsea/surface BOPs, and would yield cost savings that sum to $24,367,256. Using the share of small and large companies subject to each suite of provisions, we estimate that small companies would realize 15 percent of the cost savings from this rulemaking and large companies 85 percent. The allocation is displayed in the following table.

Cost Savings by Operator Size (Undiscounted Annualized $)

Provision	Small Companies		Large Companies		Total Cost Savings
	Percent of Operators	Cost Savings	Percent of Operators	Cost Savings	
Subsea BOP Provisions	12%	$9,588,275	88%	$71,912,061	$81,500,336
All Other Provisions	30%	$3,965,682	70%	$9,151,574	$13,117,256
TOTAL:		$13,553,957 (15% of Total)		$81,063,635 (85% of Total)	$94,617,592

This proposed rule:

a. Would have a positive economic effect on the economy of $100 million or more. The cost savings will not materially affect the economy nationally or in any local area.

b. Would not cause a major increase in costs or prices for consumers; individual industries; Federal, State, Tribal, or local governments; or regions of the nation. This proposed rule would have positive effects on OCS operators and is not anticipated to negatively impact oil, gas, and sulfur production or the cost of fuels for consumers.

c. 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.

BSEE has determined that this proposed rule is a major rule because it would have an annual effect on the economy of $100 million or more in at least one year of the 10-year period analyzed. The requirements apply to all entities operating on the OCS regardless of company designation as a small business. For more information on the small business impacts, see the IRFA in the RIA. Small businesses may send comments on the actions of Federal employees who enforce, or otherwise determine compliance with, Federal regulations to the Small Business and Agriculture Regulatory Enforcement Ombudsman, and to the Regional Small Business Regulatory Fairness Board. The Ombudsman evaluates these actions annually and rates each agency's responsiveness to small business. If you wish to comment on actions by employees of BSEE, call 1–888–REG–FAIR (1–888–734–3247).

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 Unfunded Mandates Reform Act (2 U.S.C. 1531 *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 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 proposed 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)

BSEE is committed to regular and meaningful consultation and collaboration with tribes on policy decisions that have tribal implications. Under the criteria in E.O. 13175 and DOI's Policy on Consultation with Indian Tribes (Secretarial Order 3317, Amendment 2, dated December 31, 2013), we have evaluated this proposed rule and determined that it has no substantial direct effects on federally recognized Indian tribes.

National Technology Transfer and Advancement Act (NTTAA)

BSEE complies with the National Technology Transfer and Advancement Act (NTTAA) (15 U.S.C. 3701 *et seq.*) requirement that an agency "use standards developed or adopted by voluntary consensus standards bodies rather than government-unique standards, except where inconsistent with applicable law or otherwise impractical." (OMB Circular A–119 at p. 13). BSEE also complies with the OFR regulations governing incorporation by reference. (*See,* 1 CFR part 51.) Those regulations also specify the process for updating an incorporated standard at § 51.11(a), and BSEE complies with those requirements, including seeking approval by OFR for a change to a standard incorporated by reference in a final 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, 1014–0028, 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 June 11, 2018. 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 part 250, Blowout Preventer Systems and Well Control Revisions (Proposed Rulemaking). The proposed regulations concern BOP system requirements and 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 sulfur 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 part 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 Applications for Permits to Drill (1014–0025, expiration 4/30/20); Applications for Permits to Modify (1014–0026, expiration 7/31/20); Subpart B (1014–0024, expiration 11/30/18); Subpart D (1014–0018, expiration 3/31/2021); Subpart E, (1014–0004, expiration 1/31/20); Subpart G (1014–0028, expiration 07/31/19); and Subpart Q, (1014–0010, expiration 1/31/20).

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

- APD—Proposed § 250.428 removes the requirement to resubmit an application for permit to drill (APD) in the event of planned mud losses, or remedial actions for inadequate cement jobs, if these circumstances are addressed in the original approved APD. Reductions will be shown during the renewal process (see Section by Section Discussion above).

250.724(b): BSEE is proposing to eliminate the requirement to submit certification that you have a real-time monitoring plan that meets the criteria listed. This would decrease the hour burden by 109 hours (see Section by Section Discussion above).

- Subpart A—§ 250.423 proposes rewording the requirement in a manner that would reduce the number of alternative procedure or equipment requests under § 250.141. Reductions will be shown during the renewal process (see Section by Section Discussion above).
- Subpart B—§ 250.292(p) proposes to require less information to be submitted in the DWOP. Reductions will be shown during the renewal process (see Section by Section Discussion above).
- Subpart D—§ 250.462(e)(1) would add Independent Third Party costs increasing the non-hour cost burdens by $16,000 (see Section by Section Discussion above).
- Subpart G:

§ 250.720(a)(3) would be new and would require operators to request and receive District Manager approval before resuming operations after unlatching the BOP or LMRP, and would add 13 burden hours (see Section by Section Discussion above).

§ 250.731 would add Independent Third Party costs, increasing the non-hour cost burdens by $31,000 (see Section by Section Discussion above).

§ 250.732(a) would add Independent Third Party costs, increasing the non-hour cost burdens by $765,000 (see Section by Section Discussion above).

§ 250.732(d) would eliminate the requirement to request and submit for approval all relevant information to become a BAVO. This would decrease the hour burden by 700 hours (see Section by Section Discussion above).

§ 250.737(d)(5) would be new and proposes to allow for alternating tests between two control stations; adding 25 burden hours (see Section by Section Discussion above).

§ 250.751 would be new and proposes to include the coiled tubing testing and recording requirements that were inadvertently removed in the original Well Control Rule; adding 3,630 burden hours (see Section by Section Discussion above).

BSEE-Approved Verification Organization = BAVO; is being replaced with Independent Third Party (ITP). In connection with the original WCR, BSEE assumed hour burdens in place of non-hour costs associated with BAVO submissions; however, in this proposed rule, we are capturing non-hour costs associated with hiring ITPs totaling $812,000 (+$16,000 would be added to the information collection associated with OMB Control number 1014–0018 and +$796,000 would be added to the information collection associated with OMB Control number 1014–0028). 1014–0018 and +$796,000 in 1014–0028).

If this proposed rule becomes effective, BSEE will use the current OMB control numbers for the affected subparts discussed and will have their information collection burdens adjusted accordingly through the renewal process.

National Environmental Policy Act of 1969 (NEPA)

BSEE has prepared a draft environmental assessment (EA) to determine whether this proposed rule would have a significant impact on the quality of the human environment under the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321 *et seq.*). If the final EA supports the issuance of a Finding of No Significant Impact for the rule, the preparation of an environmental impact statement pursuant to the NEPA would not be required. A copy of the draft EA can be viewed at *www.regulations.gov* (use the keyword/ID ''BSEE–2018–0002'').

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, sec. 515, 114 Stat. 2763, 2763A–153–154).

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

This proposed rule is not a significant energy action under the definition in E.O. 13211. Although the 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. In order for BSEE to withhold from disclosure your personal identifying information, you must identify any information contained in the submittal of your comments that, if released, would constitute a clearly unwarranted invasion of your personal privacy. You must also briefly describe any possible harmful consequence(s) of the disclosure of information, such as embarrassment, injury, or other harm. 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.

Severability

If a court holds any provisions of a subsequent final rule or their applicability to any persons or circumstances invalid, the remainder of the provisions and their applicability to other people or circumstances will not be affected.

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, Outer Continental Shelf—mineral resources, Outer Continental Shelf—rights-of-way, Penalties, Reporting and recordkeeping requirements, Sulfur.

Joseph R. Balash,

Assistant Secretary—Land and Minerals Management, U.S. Department of the Interior.

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

PART 250—OIL AND GAS AND SULFUR 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, 33 U.S.C. 1321(j)(1)(C), 43 U.S.C. 1334.

Subpart A—General

■ 2. Amend § 250.198 by revising paragraphs (h)(63), (h)(78), and (h)(94), and adding new paragraph (m)(2), to read as follows:

250.198 Documents incorporated by reference.

* * * * *

(h) * * *

(63) API Standard 53, Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition, November 2012, incorporated by reference at §§ 250.730, 250.734, 250.735, 250.737, and 250.739;

* * * * *

(78) API Standard 65—Part 2, Isolating Potential Flow Zones During Well Construction; Second Edition, December 2010; incorporated by reference at §§ 250.415(f) and 250.420(a)(6);

* * * * *

(94) API Recommended Practice 17H, Remotely Operated Tool and Interfaces on Subsea Production Systems, Second Edition, June 2013, Errata January 2014, incorporated by reference at § 250.734(a)(4);

* * * * *

(m) * * *

(2) ISO/IEC 17021–1—Conformity assessment—Requirements for bodies providing audit and certification of management systems—Part 1, First Edition, June 2015, incorporated by reference at § 250.730(d).

* * * * *

Subpart B—Plans and Information

■ 3. Amend § 250.292 by revising paragraph (p) to read as follows:

§ 250.292 What must the DWOP contain?

* * * * *

(p) If you propose to use a pipeline free standing hybrid riser (FSHR) on a permanent installation that utilizes a buoyancy air can suspended from the top of the riser, you must 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 associated connection system;

(2) Detailed information regarding the system used to connect the FSHR to the buoyancy air can, and associated redundancies; and

(3) Descriptions of your monitoring system and monitoring plan to monitor the pipeline FSHR and the associated connection system for fatigue, stress, and any other abnormal condition (*e.g.,* corrosion) that may negatively impact the riser system's integrity.

* * * * *

Subpart D—Oil and Gas Drilling Operations

■ 4. Amend § 250.413 by revising 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 (surface and downhole), planned safe drilling margin, and casing setting depths in true vertical measurements;

* * * * *

■ 5. Amend § 250.414 by revising paragraph (c)(3) to read as follows:

§ 250.414 What must my drilling prognosis include?

* * * * *

(c) * * *

(3) When determining the pore pressure and lowest estimated fracture gradient for a specific interval, you must consider related off-set and analogous well behavior observations, if available.

* * * * *

■ 6. Amend § 250.420 by revising paragraph (a)(6) to read as follows:

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

* * * * *

(a) * * *

(6) Provide adequate centralization consistent with the guidelines of API Standard 65—Part 2 (as incorporated by reference in § 250.198); and

* * * * *

■ 7. Amend § 250.421 by revising paragraphs (c), (d), (e), and (f) to read as follows:

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

* * * * *

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Casing type	Casing requirements	Cementing requirements
* * * * * * *		
(c) Surface	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	Use enough cement to fill the calculated annular space to at least 200 feet measured depth (MD) inside the conductor casing. When geologic conditions such as near-surface fractures and faulting exist, you must use enough cement to fill the calculated annular space to the mudline.
(d) Intermediate	Design casing and select setting depth based on anticipated or encountered geologic characteristics or wellbore conditions	Use enough cement to cover and isolate all hydrocarbon-bearing zones and isolate abnormal pressure intervals from normal pressure intervals in the well. As a minimum, you must cement the annular space 500 feet MD above the casing shoe and 500 feet MD above each zone to be isolated.
(e) Production	Design casing and select setting depth based on anticipated or encountered geologic characteristics or wellbore conditions	Use enough cement to cover or isolate all hydrocarbon-bearing zones above the shoe. As a minimum, you must cement the annular space at least 500 feet MD above the casing shoe and 500 feet MD above the uppermost hydrocarbon-bearing zone.
(f) Liners	If you use a liner as surface casing, you must set the top of the liner at least 200 feet MD 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 MD above the previous casing shoe. You may not use a liner as conductor casing. A subsea well casing string whose top is above the mudline and that has been cemented back to the mudline will not be considered a liner.	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.

■ 8. Amend § 250.423 by revising paragraphs (a) and (b) to read as follows:

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

* * * * *

(a) You must ensure that the latching mechanisms or lock down mechanisms are engaged upon successfully installing the casing string. If there is an indication of an inadequate cement job, you must comply with § 250.428(c).

(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 the liner. If there is an indication of an inadequate cement job, you must comply with § 250.428(c).

* * * * *

■ 9. Amend § 250.428 by revising paragraphs (c) and (d) 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 . . .
* * * * * * *	
(c) Have indication of inadequate cement job (such as unplanned 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; (iii) Using tracers in the cement and logging them prior to drill out; or (iv) 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,	Comply with § 250.428(c)(1), and take remedial actions. The District Manager must review and approve all remedial actions either through a previously approved contingency plan within the permit or remedial actions included in a revised permit 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, that are not included in the approved permit, will require submittal of a certification by a professional engineer (PE) certifying that they have reviewed and approved the proposed changes. You must also meet any other requirements of the District Manager for remedial actions.
* * * * * * *	

BILLING CODE 4310–VH–C

■ 10. Amend § 250.433 by revising paragraph (b) to read as follows:

§ 250.433 What are the diverter actuation and testing requirements?

* * * * *

(b) For floating drilling operations with a subsea BOP stack, you must actuate the diverter system within 7 days after the previous actuation. For subsequent testing, you may partially actuate the diverter element and a flow test is not required.

* * * * *

■ 11. Amend § 250.461 by revising paragraph (b) to read as follows:

§ 250.461 What are the requirements for directional and inclination surveys?

* * * * *

(b) *Survey requirements for directional well.* You must conduct directional surveys on each directional well and digitally record the results. Surveys must give both inclination and azimuth at intervals not to exceed 500 feet during the normal course of drilling. Intervals during angle-changing portions of the hole may not exceed 180 feet.

* * * * *

■ 12. Amend § 250.462 by revising paragraphs (b) introductory text, (e)(1)(ii), (e)(3), and (e)(4) to read as follows:

§ 250.462 What are the source control, containment, and collocated equipment requirements?

* * * * *

(b) You must have access to and the ability to deploy Source Control and Containment Equipment (SCCE) and all other necessary supporting and collocated equipment 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, which have the collective purpose to control a spill source and stop the flow of fluids into the environment or to contain fluids escaping into the environment based on the determinations outlined in paragraph (a) of this section. This SCCE, supporting equipment, and collocated equipment may include, but is not limited to, the following:

* * * * *

(e) * * *

Equipment	Requirements, you must:	Additional information
(1) * * *		
	(ii) Pressure test pressure containing 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 (if available) and an independent third party.	Pressure containing 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.
* * * * * * *		
(3) Subsea utility equipment,	Have all equipment utilized solely for containment operations available for inspection at all times	Subsea utility equipment includes, but is not limited to: Hydraulic power sources, debris removal, and hydrate control equipment.
(4) Collocated equipment designated by the operator in the Regional Containment Demonstration (RCD) or Well Containment Plan (WCP),	Have equipment available for inspection at all times	Collocated equipment includes, but is not limited to, dispersant injection equipment and other subsea control equipment

Subpart E—Oil and Gas Well-Completion Operations

■ 13. Amend § 250.518 by revising paragraph (e)(1) to read as follows:

§ 250.518 Tubing and wellhead equipment.

* * * * *

(e) * * *

(1) All permanently installed packers and bridge plugs qualified as mechanical barriers must comply with ANSI/API Spec. 11D1 (as incorporated by reference in § 250.198);

* * * * *

■ 14. Revise § 250.519 to read as follows:

§ 250.519 What are the requirements for casing pressure management?

Once you install your wellhead, you must meet the casing pressure management requirements of API RP 90 (as incorporated by reference in § 250.198) and the requirements of §§ 250.519 through 250.531. If there is a conflict between API RP 90 and the casing pressure requirements of this subpart, you must follow the requirements of this subpart.

■ 15. Revise § 250.522 to read as follows:

§ 250.522 How do I manage the thermal effects caused by initial production on a newly completed or recompleted well?

A newly completed or recompleted well often has thermal casing pressure during initial startup. Bleeding casing pressure during the startup process is considered a normal and necessary operation to manage thermal casing pressure; therefore, you do not need to evaluate these operations as a casing diagnostic test. After 30 days of continuous production, the initial production startup operation is complete and you must perform casing diagnostic testing as required in §§ 250.521 and 250.523.

■ 16. Amend § 250.525 by revising paragraph (d) to read as follows:

§ 250.525 When am I required to take action from my casing diagnostic test?

* * * * *

(d) Any well that has sustained casing pressure (SCP) and is bled down to prevent it from exceeding its MAWOP, except during initial startup operations described in § 250.522;

* * * * *

■ 17. Revise § 250.526 to read as follows:

§ 250.526 What do I submit if my casing diagnostic test requires action?

Within 14 days after you perform a casing diagnostic test requiring action under § 250.525:

You must submit either . . .	to the appropriate . . .	and it must include . . .	You must also . . .
(a) a notification of corrective action; or,	District Manager and copy the Regional Supervisor, Field Operations,	requirements under § 250.527,	submit an Application for Permit to Modify or Corrective Action Plan within 30 days of the diagnostic test.
(b) a casing pressure request,	Regional Supervisor, Field Operations,	requirements under § 250.528.	

■ 18. Amend § 250.530 by revising paragraph (b) to read as follows:

§ 250.530 What if my casing pressure request is denied?

* * * * *

(b) You must submit the casing diagnostic test data to the appropriate Regional Supervisor, Field Operations, within 14 days of completion of the diagnostic test required under § 250.523(e).

Subpart F—Oil and Gas Well-Workover Operations

■ 19. Amend § 250.601 by adding paragraph (m) to the definition of ''routine operations'' to read as follows:

§ 250.601 Definitions.

* * * * *

(m) Acid treatments

* * * * *

■ 20. Remove and reserve § 250.616.

§ 250.616 [Reserved]

■ 21. Amend § 250.619 by revising paragraph (e)(1) to read as follows:

§ 250.619 Tubing and wellhead equipment.

* * * * *

(e) * * *

(1) All permanently installed packers and bridge plugs qualified as mechanical barriers must comply with ANSI/API Spec. 11D1 (as incorporated by reference in § 250.198). You must have two independent barriers, one being mechanical, in the exposed center wellbore prior to removing the tree and/or well control equipment;

* * * * *

Subpart G—Well Operations and Equipment

■ 22. Amend § 250.712 by adding paragraphs (g) and (h) to read as follows:

§ 250.712 What rig unit movements must I report?

* * * * *

(g) You are not required to report rig unit movements to and from the safe zone during the course of permitted operations.

(h) If a rig unit is already on a well, you are not required to report any additional rig unit movements on that well.

■ 23. Amend § 250.720 by revising paragraph (a)(1) and adding paragraphs (a)(3) and (d) to read as follows:

§ 250.720 When and how must I secure a well?

(a) * * *

(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;

(iv) Observed flow outside the well's casing (*e.g.,* shallow water flow or bubbling); or

(v) Impending National Weather Service-named tropical storm or hurricane.

* * * * *

(3) If you unlatch the BOP or LMRP:

(i) Upon relatch of the BOP, you must test according to § 250.734(b)(2), or

(ii) Upon relatch of the LMRP, you must test according to § 250.734(b)(3); and

(iii) You must receive District Manager approval before resuming operations.

* * * * *

(d) For subsea completed wells with a tree installed, you must have the equipment and capabilities for intervention on those wells. All equipment utilized solely for intervention operations (*e.g.,* tree interface tools) must be readily available, maintained in accordance with OEM recommendations, and available for inspection by BSEE upon request.

■ 24. Amend § 250.722 by revising paragraph (a)(2) to read as follows:

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

* * * * *

(a) * * *

(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 indicate the well's integrity is above the minimum safety factors, if an imaging tool or caliper is used. District Manager approval is not required to resume operations if you conducted a successful pressure test as approved in your permit. You must document the successful pressure test in the WAR.

* * * * *

■ 25. Amend § 250.723 by revising the introductory text and paragraph (c)(3) to read as follows:

§ 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 on or jacked-up over a platform with producing wells or that has other hydrocarbon flow:

* * * * *

(c) * * *

(3) A MODU moves within 500 feet of a platform. You may resume production once the MODU is in place, secured, and ready to begin operations.

* * * * *

■ 26. Revise § 250.724 to read as follows:

§ 250.724 What are the real-time monitoring requirements?

(a) No later than April 29, 2019, when conducting well operations with a subsea BOP or with a surface BOP on a floating facility, or when operating in an high pressure high temperature (HPHT) environment, you must gather and monitor real-time well data using an independent, automatic, and continuous monitoring system capable of recording, storing, and transmitting data regarding the following:

(1) The BOP control system;

(2) The well's fluid handling system on the rig; and

(3) The well's downhole conditions with the bottom hole assembly tools (if any tools are installed).

(b) You must develop and implement a real-time monitoring plan. Your real-time monitoring plan, and all real-time monitoring data, must be made available to BSEE upon request. Your real-time monitoring plan must include the following:

(1) A description of your real-time monitoring capabilities, including the types of the data collected;

(2) A description of how your real-time monitoring data will be transmitted during operations, how the data will be labeled and monitored by qualified personnel, and how the data will be stored as required in §§ 250.740 and 250.741;

(3) A description of your procedures for providing BSEE access, upon request, to your real-time monitoring data;

(4) The qualifications of the personnel monitoring the data;

(5) Your procedures for, and methods of, communication between rig personnel and the monitoring personnel; and

(6) Actions to be taken if you lose any real-time monitoring capabilities or communications between rig personnel and monitoring personnel, and a protocol for how you will respond to any significant and/or prolonged interruption of monitoring capabilities or communications, including your protocol for notifying BSEE of any significant and/or prolonged interruptions.

■ 27. Revise § 250.730 to read as follows:

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

(a) You must ensure that the BOP system and system components are designed, installed, maintained, inspected, tested, and used properly to ensure well control. The working-pressure rating of each BOP component (excluding annular(s)) 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. Your BOP system must be capable of closing and sealing the wellbore in the event of flow due to a kick, including under anticipated flowing conditions for the 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 the BOP system 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 provisions of the following industry standards (all incorporated by reference in § 250.198) that apply to BOP systems:

(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 (excluding tubing with exterior control lines and flat packs) 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 ensure that the design, fabrication, maintenance, and repair of your BOP system is in accordance with the requirements contained in this part, applicable Original Equipment Manufacturers (OEM) recommendations unless otherwise directed by BSEE, and recognized engineering practices. The training and qualification of repair and maintenance personnel must meet or exceed applicable OEM training recommendations unless otherwise directed by BSEE.

(c) You must follow the failure reporting procedures contained in API Standard 53, (incorporated by reference in § 250.198), and:

(1) You must provide a written notice of equipment failure to BSEE, unless BSEE has designated a third party as provided in paragraph (d) of this section, and the manufacturer of such equipment within 30 days after the discovery and identification of the failure. A failure is any condition that prevents the equipment from meeting the functional specification.

(2) You must ensure that an investigation and a failure analysis are started within 120 days of the failure to determine the cause of the failure, and are completed within 120 days upon starting the investigation and failure analysis. You must also ensure that the results and any corrective action are documented. You must ensure that the analysis report is submitted to BSEE, unless BSEE has designated a third party as provided in paragraph (c)(4) of this section, as well as the manufacturer.

(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 changes, report the design change or modified procedures in writing to BSEE, unless BSEE has designated a third party as provided in paragraph (c)(4) of this section.

(4) BSEE may designate a third party to receive the data and reports on behalf of BSEE. If BSEE designates a third party, you must submit the data and reports to the designated third party.

(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 ANSI/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/IEC 17021–1 (as incorporated by reference in § 250.198).

(1) BSEE may consider accepting equipment manufactured under quality assurance programs other than ANSI/API Spec. Q1, provided you submit a request to the Chief, Office of Offshore Regulatory Programs for approval, containing relevant information about the alternative program.

(2) You must submit this request to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, Virginia 20166.

■ 28. Amend § 250.731 by:

■ a. Removing paragraphs (d) and (f);

■ b. Redesignating existing paragraph (e) as (d); and

■ c. Revising paragraphs (a)(5) and (c) to read as follows:

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

* * * * *

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You must submit:	Including:
(a) * * *	(5) Control system pressure and regulator settings needed to close each ram BOP under MASP as defined for the operation;
* * * * * * *	
(c) Certification by an independent third party,	Verification that: (1) Test data demonstrate 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 under the maximum environmental and operational conditions anticipated to occur at the well; (3) The accumulator system has sufficient fluid to operate the BOP system without assistance from the charging system; and (4) If using a subsea BOP, a BOP in an HPHT environment as defined in § 250.804(b), or a surface BOP on a floating facility, the BOP has not been compromised or damaged from previous service.
* * * * * * *	

■ 29. Revise § 250.732 and the section heading to read as follows:

§ 250.732 What are the independent third party requirements for BOP systems and system components?

(a) Prior to beginning any operation requiring the use of any BOP, you must submit verification by an independent third party 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;
	(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) Demonstrates the shearing capacity of the BOP equipment to the physical and mechanical properties of the drill pipe; and
	(v) Includes relevant 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 pressures (RWP) of the BOP for 5 minutes; and
	(iii) Includes all relevant test results.
(3) Calculations	Include shearing and sealing pressures for all pipe to be used in the well including corrections for MASP.

(b) The independent third-party must be a technical classification society, or a licensed professional engineering firm, or a registered professional engineer capable of providing the required certifications and verifications.

(c) For wells in an HPHT environment, as defined by § 250.804(b), you must submit verification by an independent third party that the independent third party conducted a comprehensive review of the BOP system and related equipment you propose to use. You must provide the independent third party 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 (c) 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 independent third party 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) You must make all documentation that supports the requirements of this section available to BSEE upon request.

■ 30. Amend § 250.733 by:

■ a. Revising paragraphs (a)(1) and (b)(1); and

■ b. Adding paragraph (e) to read as follows:

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

(a) * * *

(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 associated exterior control lines, and any electric-wire-, and slick-line that is in the hole and sealing the wellbore after shearing.

* * * * *

(b) * * *

(1) For BOPs installed after April 29, 2021, follow the BOP requirements in § 250.734(a)(1).

* * * * *

(e) Additional requirements for surface BOP systems used in well-completion, workover, and decommissioning operations.

The minimum BOP system for well-completion, workover, and decommissioning operations must meet the appropriate standards from the following table:

When . . .	The minimum BOP stack must include . . .
(1) The expected pressure is less than 5,000 psi,	Three BOPs consisting of an annular, one set of pipe rams, and one set of blind-shear rams.
(2) The expected pressure is 5,000 psi or greater or you use multiple tubing strings,	Four BOPs consisting of an annular, two sets of pipe rams, and one set of blind-shear rams.
(3) You handle multiple tubing strings simultaneously,	Four BOPs consisting of an annular, one set of pipe rams, one set of dual pipe rams, and one set of blind-shear rams.
(4) You use a tapered drill string,	At least one set of pipe rams that are capable of sealing around each size of drill string. If the expected pressure is greater than 5,000 psi, then you must have at least two sets of pipe rams that are capable of sealing around the larger size drill string. You may substitute one set of variable bore rams for two sets of pipe rams.
(5) You use a surface BOP on a floating facility,	The elements required by § 250.733(b)(1) of this part.

■ 31. Amend § 250.734 by:

■ a. Removing paragraphs (a)(6)(v) and (vi); and

■ b. Revising paragraphs (a)(1)(ii), (a)(3), (a)(4), (a)(6)(iv), (a)(16), and (b) to read as follows:

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

(a) * * *

When operating with a subsea BOP system, you must:	Additional requirements
(1) * * *	(ii) A combination of the 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 such as heavy-weight pipe or collars), workstring, tubing and associated exterior control lines, 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 ram(s) must be installed below a sealing shear ram(s).
* * * * * * *	
(3) Have the accumulator capacity, to provide fast closure of the BOP components and to operate all critical functions;	The accumulator capacity must: (i) Close each required shear ram, ram locks, one pipe ram, and disconnect the LMRP. (ii) Have the capability to perform ROV functions within the required times outlined in API Standard 53 with ROV or flying leads. (iii) No later than April 29, 2021, have bottles for the autoshear and deadman (which may be shared between those two systems) to secure the wellbore. These bottles may also be utilized to perform the secondary control system functions (*e.g.*, ROV or acoustic functions). (iv) Perform under MASP conditions as defined for the operation.
(4) * * *	The ROV must be capable of closing each shear ram, ram locks, one pipe ram, and disconnecting the LMRP under MASP conditions as defined for the operation. The ROV must be capable of performing these functions in the response times outlined in API Standard 53 (as incorporated by reference in § 250.198). The ROV panels on the BOP and LMRP must be compliant with API RP 17H (as incorporated by reference in § 250.198).
* * * * * * *	
(6) * * *	(iv) Autoshear/deadman functions 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.
* * * * * * *	
(16) Use a BOP system that has the following mechanisms and capabilities;	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 you suspend operations 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 an independent third party documenting the repairs and that the BOP is fit for service;

(2) Upon relatch of the BOP, perform an initial subsea BOP test in accordance with § 250.737(d)(4), including deadman in accordance with § 250.737(d)(12)(vi). If repairs take longer than 30 days, once the BOP is on deck, you must test in accordance with the requirements of § 250.737;

(3) Upon relatch of the LMRP, you must test according to the following:

(i) Pressure test riser connector/gasket in accordance with § 250.737(b) and (c);

(ii) Pressure test choke and kill stabs at LMRP/BOP interface in accordance with § 250.737(b) and (c);

(iii) Full function test of both pods and both control panels;

(iv) Verify acoustic pod communication (if equipped); and

(v) Deadman test with pressure test in accordance with § 250.737(d)(12)(vi).

(4) Receive approval from the District Manager.

* * * * *

■ 32. Amend § 250.735 by revising paragraph (a) to read as follows:

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

* * * * *

(a) An accumulator system (as specified in API Standard 53, and incorporated by reference in § 250.198). Your accumulator system must have the fluid volume capacity and appropriate pre-charge pressures in accordance with API Standard 53. 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;

* * * * *

■ 33. Amend § 250.736 by revising paragraph (d)(5) to read as follows:

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

* * * * *

(d) * * *

(5) 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. For subsea BOPs, the safety valve must be available on the rig floor if the length of casing being run exceeds the water depth, which would result in the casing being across the BOP stack and the rig floor prior to crossing over to the drill pipe running string;

* * * * *

■ 34. Amend § 250.737 by:

■ a. Removing paragraph (d)(4)(vi),

■ b. Adding paragraph (d)(13), and

■ c. Revising paragraphs (b) introductory text, (b)(2), (d)(2)(ii), (d)(3)(iii), (d)(3)(iv), (d)(3)(v), (d)(4)(i), (d)(4)(iii), (d)(4)(v), (d)(5), (d)(12)(iv) and (d)(12)(vi) to read as follows:

§ 250.737 What are the BOP system testing requirements?

* * * * *

(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 (excluding test rams and non-sealing shear rams). 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 (b) outlines your pressure test requirements.

You must conduct a . . .	According to the following procedures . . .
* * * * * * *	
(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	(i) The high-pressure test must equal the RWP 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 permit. (ii) The blind shear ram (BSR) must be tested to: (A) MASP plus 500 psi for the hole section to which it is exposed; or (B) Full well MASP plus 500 psi on initial latch up and all subsequent BSR pressure tests can be done to the casing/liner test pressure for the applicable hole section. (iii) The choke and kill side outlet valves must be tested to, except as provided in paragraph (d)(13) of this section: (A) MASP plus 500 psi for the hole section to which it is exposed; or (B) Full well MASP plus 500 psi on initial latch up and all subsequent pressure tests can be done to the casing/liner test pressure for the applicable hole section.
* * * * * * *	

* * * * *

(d) * * *

You must…	Additional requirements…
(2) * * *	(ii) Contact the District Manager at least 72 hours prior to beginning the initial test to allow BSEE representative(s) to witness testing.
(3) * * *	(iii) Contact the District Manager at least 72 hours prior to beginning the stump test to allow BSEE representative(s) to witness testing
	(iv) You must verify closure of all ROV intervention functions on your subsea BOP stack during the stump test.
	(v) You must follow paragraphs (b) and (c) of this section. Pressure testing of each ram and annular component is only required once.
(4) * * *	(i) You must begin the initial subsea BOP test on the seafloor within 30 days of the stump test.
* * * * * * *	
	(iii) You must pressure test well-control rams and annulars according to paragraphs (b) and (c) of this section.
* * * * * * *	
	(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 confirm closure of the selected ram through the ROV hot stab with a 1,000 psi pressure test for 5 minutes.
(5) Alternate tests between control stations	(i) For two complete BOP control stations you must: (A) Designate a primary and secondary station; (B) Alternate testing between the primary and secondary control stations on a weekly basis; and (C) For a subsea BOP, develop an alternating testing schedule to ensure the primary and secondary control stations will function each pod. (ii) Remote panels where all BOP functions are not included (*e.g.*, life boat panels) must be function-tested upon the initial BOP tests.
* * * * * * *	
(12) * * *	(iv) Following the deadman system test on the seafloor you must document the final remaining pressure of the subsea accumulator system.
* * * * * * *	
	(vi) You must confirm closure of the BSR(s) with a 1,000 psi pressure test for 5 minutes.
* * * * * * *	
(13) Pressure test the choke and kill side outlet valves	According to paragraph (b), except as follows: (i) For 14 day BOP testing, test the wellbore side of the choke and kill side outlet valves above the uppermost pipe ram to the approved annular test pressure. Choke and kill side outlet valves below the uppermost pipe ram must be tested to MASP plus 500 psi for the applicable hole section. (ii) For the 30 day BSR testing, test the wellbore side of the choke and kill side outlet valves between the upper most pipe ram and the upper most ram, to the casing/liner test pressure or annular test pressure, whichever is greater. (iii) For BOPs with only one choke and kill side outlet valve, you are only required to pressure test the choke and kill side outlet valves from the wellbore side.

* * * * *

■ 35. Amend § 250.738 by revising paragraphs (b)(4), (f), (i), (m), and (o) to read as follows:

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

* * * * *

If you encounter the following situation:	Then you must . . .
(b) * * *	(4) You must submit a report from an independent third party to the District Manager certifying that the BOP is fit for service
* * * * * * *	
(f) Plan to install casing rams or casing shear rams in a surface BOP stack;	Before running casing, perform a shell test to the permit approved test pressure of the BOP component above the casing ram/casing shear. 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
* * * * * * *	
(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 an independent third party certifying that the BOP is fit to return to service.
* * * * * * *	
(m) Plan to utilize any other circulating or ancillary 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 an independent third party 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.
* * * * * * *	
(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 an independent third party 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 you to provide additional information as needed to clarify or evaluate your report.
* * * * * * *	

■ 36. Amend § 250.739 by revising paragraph (b) introductory text to read as follows:

§ 250.739 What are the BOP maintenance and inspection requirements?

* * * * *

(b) A major, detailed inspection of the well control system components (including but not limited to riser, BOP, LMRP, and control pods) must be performed every 5 years. This major inspection may be performed in phased intervals. You must track and document all system and component inspection dates. These records must be available on the rig. An independent third party is required to review the inspection results and must compile a detailed report of the inspection results, including descriptions of any problems and how they were corrected. You must make these reports available to BSEE upon request. This major inspection must be performed every 5 years from the following applicable dates, whichever is later:

* * * * *

■ 37. Add § 250.750 and undesignated center heading to read as follows:

Coiled Tubing and Snubbing Operations

§ 250.750 What are the coiled tubing and snubbing requirements?

(a) For coiled tubing operations with the production tree in place, you must meet the following minimum requirements for the BOP system:

(1) BOP system components must be in the following order from the top down:

BOP system when expected surface pressures are less than or equal to 3,500 psi	BOP system when expected surface pressures are greater than 3,500 psi	BOP system for wells with returns taken through an outlet on the BOP stack
(i) Stripper or annular-type well control component	Stripper or annular-type well control component	Stripper or annular-type well control component.
(ii) Hydraulically-operated blind rams	Hydraulically-operated blind rams	Hydraulically-operated blind rams
(iii) Hydraulically-operated shear rams	Hydraulically-operated shear rams	Hydraulically-operated shear rams.
(iv) Kill line inlet	Kill line inlet	Kill line inlet.
(v) Hydraulically-operated two-way slip rams	Hydraulically-operated two-way slip rams	Hydraulically-operated two-way slip rams. Hydraulically-operated pipe rams.
(vi) Hydraulically-operated pipe rams	Hydraulically-operated pipe rams Hydraulically-operated blind-shear rams. These rams should be located as close to the tree as practical	A flow tee or cross. Hydraulically-operated pipe rams. Hydraulically-operated blind-shear rams on wells with surface pressures >3,500 psi. As an option, the pipe rams can be placed below the blind-shear rams. The blind-shear rams should be located as close to the tree as practical.

(2) You may use a set of hydraulically-operated combination rams for the blind rams and shear rams.

(3) You may use a set of hydraulically-operated combination rams for the hydraulic two-way slip rams and the hydraulically-operated pipe rams.

(4) You must attach a dual check valve assembly to the coiled tubing connector at the downhole end of the coiled tubing string for all coiled tubing operations. If you plan to conduct operations without downhole check valves, you must describe alternate procedures and equipment in Form BSEE–0124, Application for Permit to Modify and have it approved by the District Manager.

(5) You must have a kill line and a separate choke line. You must equip each line with two full-opening valves and at least one of the valves must be remotely controlled. You may use a manual valve instead of the remotely controlled valve on the kill line if you install a check valve between the two full-opening manual valves and the pump or manifold. The valves must have a working pressure rating equal to or greater than the working pressure rating of the connection to which they are attached, and you must install them between the well control stack and the choke or kill line. For operations with expected surface pressures greater than 3,500 psi, the kill line must be connected to a pump or manifold. You must not use the kill line inlet on the BOP stack for taking fluid returns from the wellbore.

(6) You must have a hydraulic-actuating system that provides sufficient accumulator capacity to close-open-close each component in the BOP stack. This cycle must be completed with at least 200 psi above the pre-charge pressure, without assistance from a charging system.

(7) All connections used in the surface BOP system from the tree to the uppermost required ram must be flanged, including the connections between the well control stack and the first full-opening valve on the choke line and the kill line.

(b) The minimum BOP-system components for operations with the tree in place and performed by moving tubing or drill pipe in or out of a well under pressure utilizing equipment specifically designed for that purpose, *i.e.,* snubbing operations, shall include the following:

(1) One set of pipe rams hydraulically operated, and

(2) Two sets of stripper-type pipe rams hydraulically operated with spacer spool.

(c) An inside BOP or a spring-loaded, back-pressure safety valve and an essentially full-opening, work-string safety valve in the open position must be maintained on the rig floor at all times during operations when the tree is removed or during operations with the tree installed and using small tubing as the work string. A wrench to fit the work-string safety valve must be readily available. Proper connections must be readily available for inserting valves in the work string. The full-opening safety valve is not required for coiled tubing or snubbing operations.

(d) Test the snubbing unit in accordance with § 250.737(a), (b), and (c).

■ 38. Add § 250.751 to read as follows:

§ 250.751 Coiled tubing testing requirements.

Coiled tubing tests. You must test the coiled tubing unit in accordance with § 250.737(a), (b), (c), (d)(9), and (d)(10). You must successfully pressure test the dual check valves to the rated working pressure of the connector, the rated working pressure of the dual check valve, expected surface pressure, or the collapse pressure of the coiled tubing, whichever is less. The test interval for coiled tubing operations must include a 10 minute high-pressure test for the coiled tubing string.

Subpart Q—Decommissioning Activities

■ 39. Amend § 250.1703 by revising paragraph (b) to read as follows:

§ 250.1703 What are the general requirements for decommissioning?

* * * * *

(b) Permanently plug all wells. Packers and bridge plugs used as qualified mechanical barriers must comply with ANSI/API Spec. 11D1 (as incorporated by reference in § 250.198). You must have two independent barriers, one being mechanical, in the exposed center wellbore prior to removing the tree and/or well control equipment;

* * * * *

■ 40. Amend § 250.1704 by adding paragraph (g)(4) and revising paragraph (h)(2) to read as follows:

§ 250.1704 What decommissioning applications and reports must I submit and when must I submit them?

* * * * *

Decommissioning applications and reports	When to submit	Instructions
* * * * * * *		
(g) * * *	(4) Within 30 days after you complete site clearance verification activities,	Include information required under § 250.1743(a).
(h) * * *	(2) Within 30 days after completion of decommissioning activity,	Include information required under §§ 250.1712 and 250.1721.
* * * * * * *		

■ 41. Remove and reserve § 250.1706:

§ 250.1706 [Reserved]

■ 42. Remove and reserve § 250.1713:

§ 250.1713 [Reserved]

■ 43. Amend § 250.1716 by revising paragraph (b)(3) to read as follows:

§ 250.1716 To what depth must I remove wellheads and casings?

* * * * *

(b) * * *

(3) The water depth is greater than 1,000 feet.

■ 44. Amend § 250.1722 by revising paragraph (d) introductory text to read as follows:

§ 250.1722 If I install a subsea protective device, what requirements must I meet?

* * * * *

(d) Within 30 days after you complete the trawling test described in paragraph (c) of this section, submit a report to the appropriate District Manager using form BSEE–0125, End of Operations Report (EOR) that includes the following:

* * * * *

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