Theresa M. Fariello
Vice President
Washington Office

July 16, 2015

U.S. Department of the Interior
Bureau of Safety and Environmental Enforcement
Attention: Regulations and Standards Branch
45600 Woodland Road
Sterling, VA 20166

Re: Bureau of Safety and Environmental Enforcement (BSEE), 30 CFR Parts 250, Oil and Gas and Sulphur Operations on the Outer Continental Shelf-Requirements - Blowout Preventer Systems and Well Control

RIN: 1014-AA11, Docket ID: BSEE-2015-0002

To Whom It May Concern:

Exxon Mobil Corporation (ExxonMobil) is writing to provide comments on the proposed rules regarding offshore oil and gas blowout preventer (BOP) systems and well control requirements with the aim of enhancing safety and environmental protection.

ExxonMobil supports revising regulations with the goal of strengthening operations integrity of oil and gas drilling in the United States Outer Continental Shelf (OCS). However, we are concerned that as currently proposed, the rules if adopted would have the opposite effect than intended and would ultimately prove detrimental to both safety and the environment. As written, the draft rules would result in significant curtailment of current and future drilling, a reduction in resource recovery from existing fields and stifled innovation and technology development in safety and environmental protection.

Risk would be increased by technically unsubstantiated and overly prescriptive rules that would prevent operators from applying the most fit-for-purpose well design and operations to the given risk profile of a drilling opportunity. The proposed rules would add such significant complexity that new potential sources of failure would be introduced into existing safely run operations. The proposed regulations would significantly increase the size, cost and footprint of a drilling facility and in many cases could not be installed or retrofitted on existing drilling and production facilities.

Two of the most significant operational aspects to be affected by the proposed rules are those of safe drilling margins and BOP equipment. The proposed safe drilling margin requirements cannot be met by a large proportion of well types drilled on the OCS, including drilling of lower-risk mature field infill wells, and would therefore result in an overall reduction of drilling activity. The requirements are based on technically flawed assumptions about drilling mud circulation and measurement that either could not be met or should not be employed to best manage risk. A recent industry survey identified approximately 110 of these types of wells that have been safely and successfully executed on OCS leases over the last 5 years under the existing rules, demonstrating industry's capability to safely manage such risk. Further, the rules would require changes to BOP design, testing and certification that may not be feasible and for which there is no current infrastructure to accommodate. Additionally, the degree of changes to design and operations prescribed by the rule would be inconsistent with global standards and practices, giving companies good reason to prioritize foreign opportunities over US opportunities.

In most cases, new requirements outlined in the proposed rules are specified without articulating any intended benefit. This makes them overly prescriptive and costly in a manner that contravenes Executive Orders 12866 and 13563. This uncertainty would have serious consequences. Without a clear benefit or objective from a requirement, industry would have no way to propose technical alternatives normally available under 30 CFR 250.141 that similarly meet or even exceed such benefits. This would make technology development and innovation unattractive in U.S. waters. The Regulatory Impact Assessment (RIA) grossly understates and in many cases omits rule impacts and does not address "undesirable side effects" as required by OMB Circular A-4. Already high costs to operate would increase up to 40% on those wells that could still be drilled, driven especially by increased BOP and equipment costs, well design changes to meet drilling margin requirements and delays caused by administrative and third-party service requirements.

As we wrote in our May 27 comments on proposed rules to establish "Requirements for Exploratory Drilling on the Arctic Outer Continental Shelf," these BOP and well control rules require more regulator and third-party interaction as well as oversight during drilling operations. Requirements to obtain endorsements by BSEE Approved Verification Organizations (which currently do not exist), to seek decisions from the regulator on active operations, and to establish extensive onshore real-time remote monitoring would all increase risk by shifting decision-making away from onsite personnel. Experienced and trained onsite personnel will have the most complete understanding of any drilling operation, especially during a dynamic situation. They are best positioned to make effective real-time decisions and minimize risk, within the bounds of governing procedures and operations integrity guidelines.

There are two attachments to this letter to further explain our concerns with the technical content of these proposed rules, with their potential impact, and to provide proposed alternatives for those that are the highest priority. The first is an appendix that provides a more technical explanation of the key concerns articulated in this letter, including examples of predicted impacts. The second is a more detailed table that identifies specific provisions of concern within the rules and offers alternative language suggestions. Given the breadth and extent of industry concerns over technical flaws and significant industry impacts and the limited time provided to respond, we urge the BSEE to conduct workshops or establish some other means for constructive engagement with industry to make sure that the regulations from this important rulemaking action are technically viable, provide the optimum risk management approach, and are in the best interest of America's economy and domestic energy security.

We have a mutual objective to have regulations in place that provide strong safety and environmental protection, and to do so in a manner that is practical, workable and effective. We would welcome any opportunity to discuss our concerns and suggestions further with the DOI.

Sincerely,

Attachment A: Summary Comments on Proposed Rules

In ExxonMobil drilling operations, focus is placed on incident prevention via a risk-based approach. We believe well control can be maintained and events managed safely when wells are designed for the range of anticipated risk, equipment has the required redundancy and is properly inspected and maintained, personnel are trained, tests and drills are conducted, and established procedures are followed. A key component of our execution philosophy is the use of onsite company representatives who provide timely and effective well control and safety decision making. In addition to our comments that follow, we recommend that BSEE consider these general operating practices when finalizing these and other regulations.

The discussion that follows is categorized into primary areas of significant concern that ExxonMobil recommend the DOI address to ensure continued safe, responsible and efficient operations in US Outer Continental Shelf (OCS) operating areas. Please see Attachment B: Detailed Comment Spreadsheet for the complete list of concerns and recommended changes corresponding with the proposed rule coding for ease of review.

Section 1: Clarity of proposed rules and Industry engagement

The proposed BOP and Well Control rules as issued by BSEE are frequently unclear in their intent and lack the definition required to ensure consistent interpretation and implementation by Industry. There is considerable uncertainty in the rules that can be attributed to the lack of Industry inclusion when attempting to strictly regulate a number of complex operational issues. In a number of instances, the current proposed rules cannot reasonably be implemented without significant increase in risk to operations, or detrimental impacts to other aspects of well design. As highlighted in the examples that follow, consultation with Industry is needed in development of the rules to provide clarity and avoid unintended consequences in the final rules.

In an attempt to improve cementing of casing strings, the proposed rules require Operators to "use a weighted fluid to maintain an overbalanced hydrostatic pressure during the cement setting time". The language and intent of the requirement is unclear as written as it does not specify whether it applies to inside the casing string or the annulus, or how hydrostatic pressure from the cement column should be considered. If intended to be in reference to the annulus fluid, such a requirement would decrease the chance of proper cement displacement and setting due to higher likelihood of lost returns, poorer displacement and the resulting lack of isolation of hydrocarbon zones. Such unintended consequences could have been addressed through consultation with industry experts, use of industry best practices or a risk based requirement (i.e. designing cement jobs such that well control is maintained throughout the operation). Issues like these are prevalent throughout the proposed rules, per the detailed comments in Attachment B, and highlight the need for further discussion and consultation with Industry.

In cases where BSEE referenced a number of API documents, the proposed rules create confusion as they do not reflect the latest versions, seek to adopt unexplained incremental requirements and unnecessarily incorporate entire documents that are already referenced by higher level standards. API standards and specifications are the end product of collaboration efforts amongst Industry experts and updates to these standards reflect the latest knowledge and experience of those experts, including incorporation of lessons learned from actual operations. As an example, there are numerous requirements beyond API Standard 53. This recent industry standard adequately addresses well control equipment and process requirements for safe operations, however, in a number of areas (i.e. for many testing protocols and minimum equipment requirements) the proposed rules seek to extend beyond these guidelines. Furthermore, BSEE are seeking to fully adopt API 16A, C and D without apparent justification of what value the entire guideline may add, and despite relevant sections from these standards already being incorporated in API Standard 53. Not only does this create confusion to those operating under the rules, but the departure from accepted industry practices drives different requirements for OCS operations than in other global regions. This is done without any justification from BSEE as to why different requirements are needed or beneficial.

In the past, with a significant rule revisions or additions, MMS/BSEE recognized that workshops with stakeholder participation provided a more comprehensive understanding of the proposed regulations and potential impacts. ExxonMobil strongly recommends that BSEE arrange such workshops with Industry to ensure clarity of intent and allow constructive consultation on proposed changes that can make the rules more workable and effective.

Section 2: Feasibility of wells challenged by proposed safe drilling margins

The proposed rules seek to enforce a number of additional requirements regarding safe drilling margins by specifying limits on the relationship between bottom hole wellbore pressure, pore pressure and formation integrity. These prescriptive requirements would impact a significant proportion of future offshore wells, making a large number uneconomic or unfeasible to drill by preventing Operators from employing a risk-based, fit-for-purpose approach as per the current regulations. Furthermore, no technical support has been provided for the proposed changes, nor are the proposals supported by accurate historical data.

The proposed rules specify that 1) static downhole mud weight (SDMW) must be greater than estimated pore pressure, 2) SDMW must be a minimum of 0.5 ppg below the lesser of the casing shoe integrity test or the lowest estimated fracture gradient, and 3) the equivalent circulating density (ECD) must be below the lesser of the casing shoe pressure integrity test or the lowest estimated fracture gradient. To better understand the implications of these requirements, an Industry workgroup comprising the American Petroleum Institute (API), the International Association of Drilling Contractors (IADC) and the Offshore Operators Committee (OOC) examined 175 wells drilled by Industry in the Gulf of Mexico and offshore California since July 2010. Under the newly proposed rules, 110 of the wells (or 63%), all of which were executed safely and successfully, would not be considered drillable as originally designed. Some of these wells may have been drillable using a different well design, but the revision may have made them uneconomic as a result of reduced production rates from a downsized completion or due to a full casing upsize. In some cases, such as at ExxonMobil's SYU offshore California operations, casing program re-design would not be able to resolve the lost circulation issue and meet the safe drilling margin as defined by the proposed rules. Under current regulations, ExxonMobil manages risk and safely executes these wells to prevent well control incidents. The proposed rules would not enable such a fit-for-purpose approach. The Regulatory Impact Assessment (RIA) needs to consider the broad impact on Industry and US energy supply that would result if a significant number of OCS wells, which have previously been executed safely, would require significant redesign or could not be drilled at all.

A further complication introduced by the proposed rules is the reliance on the term "static downhole mud weight" (SDMW). Using SDMW instead of the surface mud weight is inconsistent with current drilling best practices and would introduce risk and inefficiencies by confusing onsite personnel and complicating well control operations. SDMW can only be inferred by downhole tools during specific limited periods of operations when additional pressure loads are not present in the wellbore (i.e., no cuttings in the wellbore, pumps off, temperature equilibrium reached, etc). Unlike surface mud weight, SDMW is not a readily accessible parameter during active operations. The proposed regulations should focus on keeping rig site implementation simple to execute and consistent with current safe operating practices. Building on existing proven processes that utilize surface mud weight is strongly recommended.

As an unintended consequence of the proposed safe drilling margin requirements, innovative technologies like managed pressure drilling (MPD), which is a proven technology applied within Industry, would be limited in application for OCS operations. One variant of MPD utilizes a combination of surface mud weight and surface applied pressure to provide an equivalent mud weight to control pore pressure. Its application is most beneficial in narrow margin environments and can in certain situations enhance overall well control. Not only would the safe drilling margin limits heavily restrict the potential benefits that MPD could offer, but obtaining the desired SDMW readings would be further challenged due to the specifics of the MPD process. Using surface mud weight eliminates this issue and is the approach used across existing global operations where MPD technology is frequently deployed. Implementation of the rule as written would hinder the ability of operators to utilize and further develop this important enabling technology in the USA. A risk based approach to managing drilling margins would enable such technologies.

Without additional consideration and revision to the proposed safe drilling margin rules as discussed above, the level of OCS activities would be significantly reduced resulting in a decline in production, jobs and federal revenue as operators seek other global opportunities for investment. Based on Industry performance in OCS operations, no change is needed to existing regulations. In the event BSEE seeks to address safe drilling margins in the proposed rules, the requirement should be revised to reflect a risk-based approach that enables Operators to assess the unique risks for each well and apply applicable Industry best practices and technologies to manage environments with narrow drilling margins and/or increased potential for lost return intervals.

Section 3: Incremental BOP requirements with minimal or no net benefit

A large portion of the proposed rules addresses requirements for the BOP that are incremental to recommendations established by Industry experts via documents such as API Standard 53. These requirements above and beyond the API Standard 53 introduce additional complexity and risks to BOPs and their control systems without BSEE providing adequate justification or support for the changes. As many of the proposed changes have not been considered in the RIA, Industry is concerned that BSEE may not completely understand the potential significance and cumulative side-effects of all the proposals. It is imperative that BSEE provide a specifically defined benefit objective for each proposed deviation and provide Industry the opportunity for further engagement to avoid inadvertently increasing operational risk.

Enhanced ROV function capability, beyond that already defined in API Standard 53, provides a good example of unjustified requirements that potentially increase system failure risk. These additions are incorporated in the proposed rules without any impact assessment. As written, the proposed rules require ROV function capability on all rams, choke and kill outlets, and Lower Marine Riser Packages (LMRPs). These requirements unnecessarily exceed the current API Standard 53. The numerous shuttle valve, control panel and ROV manifold additions would result in restricted access for maintenance and increase potential system leak paths and failure points. Furthermore, these upgrades could require disabling fail-safe-close systems or the need for plumbing more complicated circuits. Additional exposure would be created on BOP stacks that exceed minimum preventer requirements as, under the proposed rules, they are required to incorporate incremental ROV function capabilities too. To avoid these unintended complications, BSEE should avoid requirements beyond API Standard 53 or complete a comprehensive analysis of the specific net risk, cost and operational impacts as a result of each proposed change.

A number of the proposed changes to increase testing requirements of shear and pipe rams cannot be currently met by Industry nor are they addressed by any existing industry standards. The rules require Operators to verify that "the BOP was designed, tested and maintained to perform at the most extreme anticipated conditions." This is generally interpreted by Industry as a worst case discharge scenario. Shearing and sealing on flowing wells at worst case discharge rates is not a typical drilling BOP shut in scenario nor do equipment manufacturers have the ability to test, and therefore certify, equipment under these conditions. In fact, the BOEM report on the Macondo incident (September 14, 2011) states that "the Agency should consider researching the effects of a flowing well on the ability of a subsea BOP to shear pipe." To the best of our knowledge, this research has not been done. Furthermore, capping stacks are available with flow outlet valves specifically designed for shut in on worst case discharge situations if required. If this proposed regulation is adopted, every BOP currently in use would not meet the regulation and the Original Equipment Manufacturer (OEM) would not be able to provide supporting documentation that a BOP component would close and seal on every conceivable well flow condition. The proposed rule should be revised to require the BOPs to be designed, tested and maintained to perform at anticipated conditions and BSEE emphasis should be more on early detection and correct shut in procedures rather than shutting a BOP at worst case discharge conditions.

There are also a number of BOP operating requirements which are highly prescriptive in nature, technically deficient, and may potentially increase risk as a result. As an example, the proposed rule 250.734 (a) (6) seeks to impose a blanket requirement on the emergency function sequence to close both the casing shear and blind shear ram in all situations. This is directly counter to the industry best practice of developing operation-specific, risk based sequences. For most drilling situations, it is not necessary or desired to close the casing shear rams. Furthermore, execution of unnecessary functions increases the risk of delaying or not achieving a safe disconnect and preserving wellhead integrity. The complexity and extent of the implications of the proposed rules in this area would be best addressed through direct engagement with industry experts in a workshop or other technical exchange forums to ensure that regulations allow Operators to manage risk rather than follow an arbitrary checklist in dealing with emergency situations.

Overly restrictive maintenance and inspection requirements of BOPs and associated equipment are also introduced by the proposed rules. As an example, the rules seek to implement a complete re-certification of the "entire" BOP system every 5 years. Under API Standard 53, Industry currently completes 5 year re-certification of BOP systems; however, they are completed in a phased approach so as to distribute the workload, minimize failure risk of the overall system, and decrease critical path impact to active operations. The proposed rule would force most rigs out of operations for several months due to the volume of sub-systems needing to be inspected. Furthermore, no justification has been provided as to why the current global practice is unacceptable, and the impact has not been considered as part of the RIA. As with many of the proposed BOP rule changes, we recommend that BSEE remain consistent with guidelines provided by API Standard 53.

Several of the proposed regulations would significantly increase minimum requirements for BOP accumulator bottle sizing and charging systems beyond global Industry standards. Rule 250.734(a)(3) implies that dedicated subsea accumulator bottles would be required for Emergency Disconnect Sequence (EDS), deadman and autoshear systems. This is a major deviation from API Spec 16D and API Standard 53 which allow surface bottles to contribute to the EDS sequence. For the subsea bottles to control the EDS sequence specified in the rule, two to three times the number of bottles currently required on a subsea BOP would be required, resulting in substantial upgrades, additional subsea infrastructure, and potentially additional failure points. None of these has been addressed in the RIA. Since most rigs are built to meet established API requirements, a high percentage of current rigs would not meet BSEE requirements to work in OCS waters. Workshops with BSEE and industry experts would enable further discussion on accumulator sizing philosophies and development of more appropriate regulations for OCS operations.

The examples provided above cover only a few of the high impact BOP changes included in the proposed rules that need further consideration and evaluation by BSEE. Further details and discussion of the primary concerns are provided in Attachment B and will require additional engagement with Industry to ensure that practical regulations can be developed that do not compromise the integrity of such a critical component of well control and safety.

Section 4: BSEE assumed responsibility, accountability and liability

The proposed rules consider shifting decision-making authority away from Operators and their rig site personnel via implementation of BSEE Approved Verification Organizations (BAVOs) and prescriptive real time monitoring requirements. The increased engagement of BSEE in ongoing operations would distort the lines of responsibility and accountability, and create confusion that could decrease overall operations integrity. It is critical that regulations ensure that Operators have clear authority for their respective operations and that the rules focus on specifying the range of risks that need to be addressed.

During any given operation the onsite personnel have the best understanding and most complete picture of the current operation, key risks, and critical considerations. In addition, their experience in active operations best positions them to make effective real-time decisions within the bounds specified by the Operator's governing procedures and operations integrity guidelines. This role includes full control of the operations and the full authority to stop activities at any time.

Utilizing shore base decision-making from real-time data centers, as indicated by the proposed rules, has the potential to decrease offshore personnel's authority which is critical to maintaining safe operations and responding to emergency situations. In times of communication interruptions or significant offshore events (well control, station keeping difficulties, vessel collisions, equipment failure, etc.) there is generally insufficient time to interact with shore base command centers to plan or seek approval for an immediate response. In these critical moments, offshore supervision is key, and its effectiveness can be maintained only if the primary decision-making remains focused at location, even during routine operations. To provide offshore personnel with the necessary knowledge prior to specific operations, a range of preparatory engagements are held with the shore base engineering and operations support teams or through on-site engineering assistance. In these engagements, the key risks and critical steps are discussed to prepare the offshore team for the upcoming operations, including discussion of potential risks and appropriate responses. As operational issues arise, support is provided by shore-based organizations, leveraging real-time information, but authority remains in the field. This approach should be maintained for all active drilling operations.

Across ExxonMobil and its affiliate's existing global operations, real time monitoring is employed in an effective manner that enhances operations integrity without creating additional exposure. On rigs that we or our affiliates operate, trained employees are onsite to oversee the operations. These personnel take on key leadership roles onsite to confirm that safety, environmental and well control standards are met. In addition to onsite monitoring, we also frequently employ a range of real time data feeds to assist our offsite engineers in analyzing trends and further enhancing our performance on subsequent hole sections and future wells. This data is available for viewing from individual engineers' workstations and is commonly reviewed by the broader offsite team in regular surveillance discussions, especially during critical operations. Due to our existing, robust real time monitoring system, and due to the risks discussed previously, we do not believe that BSEE's proposed level of real time monitoring (i.e. offsite oversight) is appropriate or necessary. Shifting the proposed regulation to a performance based requirement of a Real Time Monitoring Plan would enable Operators to provide a description of their capability and discuss how it would assist in maintaining overall operations integrity without inadvertently increasing risk.

In proposing the BSEE Approved Verification Organizations (BAVOs), another exposure area is created where responsibility, accountability, and liability of BSEE needs to be clarified. The proposal includes BAVO certification in a range of areas such as BOP shear capabilities, BOP design and maintenance, BOP application in HPHT wells, and capping stacks. Currently no BAVOs exist, which may result in delays/shutdowns upon the effective date of this rule until BSEE establishes such organizations with the necessary qualified staff. If the mandate is retained in the final rules, requirements for certification by BAVOs should not take effect until at least 12 months after an initial BAVO list is published to enable Operators sufficient time to engage the agencies and contract the required services. Additionally, BSEE should provide industry with the opportunity to comment on the intended detailed workscope for BAVOs.

As with all oversight and decisions related to active offshore operations, there is a certain level of risk, responsibility and accountability. In the event that BSEE seeks to further engage in these decisions either indirectly on equipment certification via BAVOs or directly during active drilling operations, clarification is required on the associated responsibility, accountability and liability that would be assumed by BSEE in the event of any incidents that occur in connection with those actions. It is for these reasons that it is strongly recommended the BSEE leave validation of equipment certification and key operational decision-making in the hands of the Operators and focus regulations on ensuring the associated risks are addressed.

Section 5: Proposed prescriptive rules vs risk-based approach

Despite several references within the rules to Executive Order 13563, which states that the regulations should "specify performance objectives, rather than specifying the behavior or manner of compliance," the proposed regulations are highly prescriptive and do not attempt to utilize performance or risk based objectives. As a result of the prescriptive approach, not only do the proposed rules have very limited ability to adapt to the wide range of operations to which they would apply, but a number of significant unintended consequences are created as discussed previously in this attachment.

The proposed Source Control and Containment Equipment (SCCE) requirements highlight this concern, as an "all-of-the-above" requirement is proposed regardless of assessed risk or operational plans. The new rules require Operators to prepare for "Cap and Flow" as part of their SCCE measures. In the current Gulf of Mexico operations, Operators are not required to source "Cap and Flow" equipment if the well design is such that it can be shut in on a full column of hydrocarbons (i.e. "Cap and Contain" design). "Cap and Flow" preparations result in redundant equipment for a well which can be safely capped and contained, and only add incremental risk to operations. This arbitrary "all-of-the-above" requirement would further increase costs of operating in OCS areas without driving any net benefit for safety or environment, especially in areas outside of the Gulf of Mexico where established response organizations like the Marine Well Containment Company do not operate. The proposed SCCE requirements should acknowledge the different levels of response that may be needed and enable Operators to utilize equipment applicable to their specific operation.

Similar prescriptive language is used in the rules in reference to BOP stack requirements. The proposed rules increase the minimum equipment requirements beyond API Standard 53 and seek to introduce one-size-fits-all configurations. As an example of the detailed prescriptive requirements, the proposed rules specify the installation of gas bleed lines under both annulars. Industry interprets this requirement as a desire to de-risk issues associated with trapped gas in a BOP stack following a well control event; however, a number of operational steps exist that can meet this requirement without introducing complex hardware upgrades (i.e. additional bleed lines) that may not be feasible on a number of rigs. Rather than focus on particular equipment requirements, the proposed rules should define the risks that a BOP stack must be capable of mitigating (such as trapped gas) and enable Operators to risk assess how that can be achieved.

Re-writing the proposed rules with a risk-based approach would enable BSEE to create a set of rules that could meet the desired intent without creating a number of unintended side effects. A risk-based approach would also be more suited to the constant evolution of drilling processes and encourage technological innovation and efficiency.

Section 6: Economic impact to both new and existing OCS projects / activities

BSEE's Regulatory Impact Assessment (RIA) asserts that the cost of implementing the proposed rules will be offset by savings associated with decreased BOP testing on workover operations and a potential reduction in spills. ExxonMobil strongly disagrees with this conclusion. ExxonMobil's assessments indicate that a typical deepwater Gulf of Mexico well would experience a cost increase of up to 30% relative to today's standards under existing regulations without a reduction in risk. For an Industry that spends billions of dollars in OCS operations each year, this is a significant impact. The estimated cost increase is driven primarily by revised well designs that would be needed to meet the drilling margin requirements, increased BOP equipment requirements, and the administrative burden of the incremental reporting and third party services, as highlighted throughout this attachment. Furthermore, a number of prospects would no longer be feasible to drill, due to the proposed drilling margin requirements. This would all result in decreased OCS activity. The RIA fails to address these concerns due to the underestimation and in some cases neglect of certain impacts of the proposed rules. It also fails to acknowledge the significant economic disadvantage that would be placed on OCS prospects compared to other global opportunities, and the associated impacts that the rule would have on domestic oil and gas supply, jobs and GDP.

As an example, the time and cost for a range of significant BOP upgrades, including items like hydraulic locks for surface BOPs and accumulation requirements for subsea BOPs to meet the new rules, have been underestimated or left uncalculated. Requiring hydraulic locks on all surface BOPs is a significant undertaking that would require detailed planning and installation time. BSEE has included no data or preliminary estimate of the potential impact, but instead has requested Industry to provide the assessment information. Similarly, the proposed subsea accumulator requirements would drive most rigs to require stand-alone subsea accumulation to meet the requirements, resulting in capital equipment and installation costs on every well, none of which has been considered in the RIA. As a result of the combined BOP requirements, it is also likely that a number of currently acceptable rigs would no longer be able to operate in OCS waters, therefore leading to higher day-rates which have not been included in the assessment. The failure to address such significant impacts, while claiming the rules provide a net benefit to industry, is not reasonable or accurate. In addition, the number of items omitted from the RIA imply a lack of understanding of the extent, practicality and significance of the proposal, further demonstrating the need for engagement with Industry.

The current RIA fails to adequately assess potential impacts to both existing facilities and upcoming or future projects. Although the assessment covers a ten-year period, which might be sufficient to cover the general implementation of the proposed rules, there is no consideration given to the ongoing impact on all OCS projects. Typical offshore developments can have life cycles of 20-30 years, and the proposed rules would result in a higher relative cost to do business in the US than in other regions; therefore it is critical for the assessment to consider the associated later life impacts that add increased burden to new development projects. Existing facilities would also face significant challenges, as no "grandfathering" scheme has been provided. Many safely-run existing facilities, designed to the appropriate standards at the time of construction, would be unable to meet the proposed rules without significant upgrades. This could ultimately result in a number of facility shutdowns. These potential impacts need to be addressed in the RIA or resolved through an appropriate "grandfathering" provision.

In summary, the RIA fails to adequately assess the impact of the proposed rules. ExxonMobil's assessment indicates the cost would be in excess of $25B and correlates with other independent assessments. By comparison, BSEE estimates the total cost impact at under $1B. Furthermore, these estimates do not include any secondary impacts associated with reduced OCS activity and production. Rather than create a net benefit to Industry, the proposed rules would result in a significant premium for OCS operations and challenge global competitiveness. To ensure that potential impacts are properly assessed, BSEE needs to utilize the comments provided by Industry to revise the RIA and address the impacts that were previously overlooked or underestimated. If each proposed change does not sufficiently reduce risk to justify its cost then it should be removed. Given the potential implications, the revised RIA should be shared with the public before progressing with any final rule revisions.

<u>As highlighted throughout this attachment, the current prescriptive nature of the proposed rules creates a variety of unintended consequences that may increase risk or at a minimum, increase costs without any net safety, environmental, or operational benefit.</u> To ensure that Industry can continue to improve overall operations integrity, it is critical that these proposed regulations, and any future revisions, seek to enhance incident prevention and focus on risk-based requirements to drive fit-for-purpose solutions to each unique operation. To achieve this goal, continued dialogue and interaction between regulators and Industry experts is paramount to ensure that the associated risk and secondary impacts are understood and addressed.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.198(h)(51)	Documents incorporated by reference.	(51) API RP 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), First Edition, June 1998; Reaffirmed May 2006, Errata June 2009; incorporated by reference at §§ 250.292, 250.733, 250.800, 250.901, and 250.1002	(51) API RP 2RD, Recommended Practice for Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), Second Edition, September 2013; reaffirmed, May 2006, Errata, June 2009; incorporated by reference at §250.800; 250.901 and 250.1002;	Should reference the most recent edition. 2nd edition of 2RD, September 2013
§250.198(h)(63)	Documents incorporated by reference.	(63) API Standard 53, Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition, November 2012; incorporated by reference at §§ 250.730, 250.737, and 250.739;		Reference API 53 in its entirety with regards to 16A, 16C, 16D, and 17H, such that only the relevant provisions of those references apply. The editions of API 16A, 16C, 16D, and 17H should be those that were in effect at the date of manufacture of the specific equipment.
§250.198(h)(68)	Documents incorporated by reference.	(68) ANSI/API Spec. Q1, Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry, ISO TS 29001:2007 (Identical), Petroleum, petrochemical and natural gas industries—Sector specific requirements—Requirements for product and service supply organizations, Eighth Edition, December 2007, Effective Date: June 15, 2008; incorporated by reference at §§ 250.730 and 250.806	API Spec. Q1, Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry, Ninth Edition, June 2013, incorporated by reference at § 250.730 and 250.806	
§250.198(h)(70)	Documents incorporated by reference.	(70) ANSI/API Spec. 6A, Specification for Wellhead and Christmas Tree Equipment, Nineteenth Edition, July 2004; Effective Date: February 1, 2005; Contains API Monogram Annex as Part of U.S. National Adoption; ISO 10423:2003 (Modified), Petroleum and natural gas industries—Drilling and production equipment—Wellhead and Christmas tree equipment; Errata 1, September 2004, Errata 2, April 2005, Errata 3, June 2006, Errata 4, August 2007, Errata 5, May 2009; Addendum 1, February 2008; Addendum 2, 3, and 4, December 2008; incorporated by reference at §§ 250.730, 250.806, and 250.1002		Reference API 53 in its entirety with regards to 6A, such that only the relevant provisions of those references apply. The edition of API 6A should be the one that was in effect at the date of manufacture of the specific equipment.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.198(h)(89)	Documents incorporated by reference.	(89) ANSI/API Spec. 11D1, Packers and Bridge Plugs, ISO 14310:2008 (Identical), Petroleum and natural gas industries—Downhole equipment—Packers and bridge plugs, Second Edition, Effective Date: January 1, 2010; incorporated by reference at §§ 250.518, 250.619, and 250.1703	(89) ANSI/API Spec. 11D1, Packers and Bridge Plugs, ISO 14310:2008 (Modified), Petroleum and natural gas industries—Downhole equipment—Packers and bridge plugs, Third Edition, Effective Date: October, 9 2015; incorporated by reference at §§ 250.518, 250.619, and 250.1703	
§250.198(h)(90)	Documents incorporated by reference.	(90) ANSI/API Spec. 16A, Specification for Drill-through Equipment, Third Edition, June 2004; incorporated by reference at § 250.730		Reference API 53 in its entirety with regards to 16A, such that only the relevant provisions of those references apply. The edition of API 16A should be the one that was in effect at the date of manufacture of the specific equipment.
§250.198(h)(91)	Documents incorporated by reference.	(91) ANSI/API Spec. 16C, Specification for Choke and Kill Systems, First Edition, January 1993; incorporated by reference at § 250.730		Reference API 53 in its entirety with regards to 16C, such that only the relevant provisions of those references apply. The edition of API 16C should be the one that was in effect at the date of manufacture of the specific equipment.
§250.198(h)(92)	Documents incorporated by reference.	(92) API Spec. 16D, Specification for Control Systems for Drilling Well-control Equipment and Control Systems for Diverter Equipment, Second Edition, July 2004; incorporated by reference at § 250.730;		Reference API 53 in its entirety with regards to 16D, such that only the relevant provisions of those references apply. The edition of API 16D should be the one that was in effect at the date of manufacture of the specific equipment.
§250.198(h)(93)	Documents incorporated by reference.	(93) ANSI/API Spec. 17D, Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment, Second Edition; May 2011; ISO 13628-4 (Identical), Design and operation of subsea production systems-Part 4: Subsea wellhead and tree equipment; incorporated by reference at § 250.730;		Reference API 53 in its entirety with regards to 17D, such that only the relevant provisions of those references apply. The edition of API 17D should be the one that was in effect at the date of manufacture of the specific equipment.
§250.198(h)(94)	Documents incorporated by reference.	(94) ANSI/API RP 17H, Remotely Operated Vehicle Interfaces on Subsea Production Systems, ISO 13628-8:2002 (Identical), Petroleum and natural gas industries—Design and operation of subsea production systems—Part 8: Remotely Operated Vehicle (ROV) interfaces on subsea production systems, First Edition, July 2004, Reaffirmed: January 2009; incorporated by reference at § 250.734		Reference API 53 in its entirety with regards to 17H, such that only the relevant provisions of those references apply. The edition of API 17H should be the one that was in effect at the date of manufacture of the specific equipment.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.292(p)	What must the DWOP contain?	If you propose to use a pipeline free standing hybrid riser (FSHR) that utilizes a critical chain, wire rope, or synthetic tether to connect the top of the riser to a buoyancy air can, provide the following information in your DWOP in the discussions required by paragraphs (f) and (g) of this section: (1) A detailed description and drawings of the FSHR, buoy and the tether system; (2) Detailed information on the design, fabrication, and installation of the FSHR, buoy and tether system, including pressure ratings, fatigue life, and yield strengths; (3) A description of how you met the design requirements, load cases, and allowable stresses for each load case according to API RP 2RD (as incorporated by reference in § 250.198); (4) Detailed information regarding the tether system used to connect the FSHR to a buoyancy air can; (5) Descriptions of your monitoring system and monitoring plan to monitor the pipeline FSHR and tether for fatigue, stress, and any other abnormal condition (e.g., corrosion) that may negatively impact the riser or tether; and (6) Documentation that the tether system and connection accessories for the pipeline FSHR have been certified by an approved classification society or equivalent and verified by the CVA required in Subpart I; and	If you propose to use a permanent pipeline free standing hybrid riser (FSHR) that utilizes a critical chain, wire rope, or synthetic tether to connect the top of the riser to a buoyancy air can, provide the following information in your DWOP in the discussions required by paragraphs (f) and (g) of this section: (1) A detailed description and drawings of the FSHR, buoy and the tether system; (2) Detailed information on the design, fabrication, and installation of the FSHR, buoy and tether system, including pressure ratings, fatigue life, and yield strengths; (3) A description of how you met the design requirements, load cases, and allowable stresses for each load case according to API RP 2RD (as incorporated by reference in § 250.198) and/or current approved industry standard at the date of manufacture; (4) Detailed information regarding the tether system used to connect the FSHR to a buoyancy air can; (5) Descriptions of your monitoring system and plan for on-line monitoring the riser top tension variation for a permanent FSHR system; and (6) Documentation that the tether system and connection accessories for the pipeline FSHR have been certified by a suitable classification society or equivalent and verified by the CVA required in Subpart I; and	Regulation should only consider permanent risers since exploration wells are not covered under DWOP and risers for source control are not part of a permanent installation. For subsection 6, reference cannot be made to an 'approved' classification society as no definition has been provided.
§250.292(p)(3)	What must the DWOP contain?	(3) A description of how you met the design requirements, load cases, and allowable stresses for each load case according to API RP 2RD (as incorporated by reference in § 250.198);	(3) A description of how you met the design requirements, load cases, and allowable stresses for each load case according to API RP 2RD (as incorporated by reference in § 250.198); and/or current approved industry standard at the date of manufacture;	

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.413(g)	What must my description of well drilling design criteria address?	A single plot containing curves for estimated pore pressures, formation fracture gradients, proposed drilling fluid weights, maximum equivalent circulating density, and casing setting depths in true vertical measurements;	A single plot containing estimated pore pressures, formation fracture gradients, proposed drilling fluid weights, equivalent circulating density at the shoe or identified weakest zone (using maximum interval mud weight and flow rate), and casing setting depths in true vertical measurements. This plot will be used for design purposes only.	This rule requires entry of ECD information into the APD pore pressure/fracture gradient plot. Clarification is needed as to how (depth, mud weight, pump rate) this ECD is expected to be calculated and used. Clear direction is needed to avoid incorrect assumptions, such as comparing actual field data with calculated data since these may be taken at different depths (measured ECD depth may be thousands of feet below the calculated ECD depth at a shoe).
§250.414(c)	What must my drilling prognosis include?	(c) Planned safe drilling margins between proposed drilling fluid weights and the estimated pore pressures, and proposed drilling fluid weights and the lesser of estimated fracture gradients or casing shoe pressure integrity test. Your safe drilling margins must meet the following conditions:		Overall, this requirement is heavily restrictive and would eliminate the ability to drill a large number of wells that are routinely and safely drilled in current OCS operations. Any final safe drilling margin requirements should specify their application only to active drilling operations and not other operations such as cementing or completion activities.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.414(c)(1)	What must my drilling prognosis include?	(1) Static downhole mud weight must be greater than estimated pore pressure;	Mud weight plus surface pressure must be greater than estimated pore pressure throughout the open hole interval.	Static downhole mud weight (SDMW) can only be measured by downhole MWD/LWD tools during pumps off operations like connections. It is then transmitted to surface when the pumps are turned back on. As such, it is not constantly known while actively drilling. In addition, the SDMW is effected by several factors: cuttings loading, cuttings density, compression, temperature, mud rheology, drilled gas/fluids, etc. To obtain an actual SDMW during the drilling process requires the well to be circulated clean to remove the cuttings from the mud. During the drilling process, bottoms up cycles are typically only performed prior to trips out of the hole, and/or when borehole conditions indicate the need, and/or to observe the cuttings, and/or as otherwise required. Therefore, while drilling it may be several hours before actual SDMW readings (i.e. those not effected by cuttings loading and cuttings density) are transmitted to surface. Furthermore, rig personnel cannot directly measure the SDMW. They can only measure surface mud weight. The mud engineer knows the mud weight of the mud in the pits. The shaker hand knows the mud weight returning from the well, and the mud weight can be measured downstream of the mud processing equipment such that cuttings do not affect the weight. In addition, a pressurized mud balance can be used to determine the surface mud weight if there is entrained gas in the mud. The mud weight in and the mud weight out is either called out over the rig's intercom system or displayed on the rig's digital data system on a regular basis such that the rig personnel are always aware of the mud weight, especially the driller. Therefore, requiring SDMW to be the mud weight basis could lead to confusion on the rig and compromise well control.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.414(c)(2)	What must my drilling prognosis include?	(2) Static downhole mud weight must be a minimum of one-half pound per gallon below the lesser of the casing shoe pressure integrity test or the lowest estimated fracture gradient;	It is recommended to delete 250.414 (c) 2.	ExxonMobil acknowledges the safety concerns BSEE has regarding drilling margins and the need for increased vigilance. Avoidance of incidents is paramount, especially in difficult hole sections. Industry has consistently shown the ability to be able to drill without arbitrary prescriptive safety margins, through safe drilling practices. Using a "Safe" Drilling Margin should result in Well Control and kick recognition being maintained when drilling ahead, with or without losses. The "Safe" Drilling Margin should be risk assessed and calculated based on sound engineering practices. It should be reassessed if lost circulation occurs or conditions change. An unintended consequence is that an operator may be forced to drill very near to balance to maintain the mandated "Safe" Drilling Margin in order to achieve the well objectives, incurring unanticipated, unnecessary risks. Alternatively, to meet the "Safe" drilling margin requirement, an operator may be forced into setting surface casing deeper into a pressured environment. A review of 175 OCS wells drilled after July 2010 found that 63% could not have been drilled as designed under the proposed new rules, all of which were executed without a major well control incident under the existing regulations.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.414(c)(3)	What must my drilling prognosis include?	(3) The equivalent circulating density must be below the lesser of the casing shoe pressure integrity test or the lowest estimated fracture gradient;	The equivalent circulating density must be below the estimated wellbore integrity at each point throughout the open hole; if this requirement cannot be met and lost circulation is anticipated, then a risk assessment shall be held and a lost returns contingency plan developed to address the associated risks.	Wells can and are successfully drilled with both partial and complete lost returns when processes ensure the static downhole mud weight and/or the ECD are overbalanced to the pore pressure. This proposed rule would make some wells with narrow margin windows, including additional recovery wells in depleted reservoirs, un-drillable. To maintain a stable wellbore with respect to wellbore instability (driven by tectonically stressed areas such as near salt, or high angle directional drilling) the mud weight must be further increased, over and above the mud weight required to control the pore pressure, to counter the stresses trying to collapse the hole. Thus there are a range of wells (including deepwater and HPHT) where it is common to experience some losses, as there is limited window remaining when the ECD is applied to wellbore. Similar issues occur in depleted formations in which formation integrity has correspondingly decreased with production. As an example, in ExxonMobil operations offshore the coast of California at SYU, it is common to drill into the Monterrey formation with 8.7 ppg seawater or just slightly higher and have lost returns while drilling the formation interval, which may be over 1000 ft in length. Lost circulation materials provide minimal benefit in the pre-existing fractured Monterrey formation. Setting casing will not resolve the lost returns issue. ExxonMobil has been able to successfully drill these wells and enable development of the reserves through a specific, risk based approach. This rule should be rescinded as it would not reduce work program risk and a risk-based approach should be adopted to enable a fit-for-purpose approach on individual wells.
§250.414(c)(4)	What must my drilling prognosis include?	(4) When determining the pore pressure and lowest estimated fracture gradient for a specific interval, you must consider related hole behavior observations.	(4) When determining the pore pressure and lowest estimated fracture gradient during planning for a specific interval, relevant offset hole behavior observations must be considered.	This section is for planning (prognosis) purposes and should not be applied to operations.
§250.414(k)	What must my drilling prognosis include?	(k) Any additional information required by the District Manager.	(k) Any additional information required by the District Manager that could be reasonably expected to have a significant impact on overall operational risk.	Requirement is ambiguous and should be clarified

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.420	What well casing and cementing requirements must I meet?	You must case and cement all wells. Your casing and cementing programs must meet the applicable requirements of this subpart and of Subpart G.		
§250.420(a)(6)	What well casing and cementing requirements must I meet?	(6) Provide adequate centralization to ensure proper cementation; and	(6) Provide adequate centralization and/or other methods to aid proper cementation, to meet well design objectives within the constraints imposed by hydraulic, operational, logistical or well architecture limitations (ref. Standard 65-2 2nd Edition Appendix D1); and	This regulation is deemed to be overly prescriptive. There are cases where it may not be possible to centralize pipe, such as tight clearances in deepwater and directional well designs. There are instances where doing so may actually increase risk by increasing the potential for stuck pipe, lost circulation, and damage to wellhead components. Other methods are available that can meet the cementing requirements. API Standard 65-2, 2nd Edition provides in-depth information regarding best cementing practices other than centralization.
§250.420(c)(2)	What well casing and cementing requirements must I meet?	(2) You must use a weighted fluid to maintain an overbalanced hydrostatic pressure during the cement setting time, except when cementing casings or liners in riserless hole sections.	(2) You must use a weighted fluid in the center of the wellbore to maintain an overbalanced hydrostatic pressure during the cement setting time, except when cementing casings or liners in riserless hole sections.	It is unclear if this regulation refers to the annular fluid column or the fluid column in the center of the well. If it refers to the annular fluid column, the regulation is problematic for the following reasons: 1) The proposed rule would have unintended consequences. Increasing mud weight to replace pressure reduction during cement hydration increases risk of lost circulation and may result in failure to attain the required TOC. 2) The proposed rule is not technically sufficient. Although increasing the pressure applied to the cement slurry increases the critical gel strength value by increasing the initial overbalance pressure, this pressure is not transmitted through the cement slurry during the slurry's Critical Gel Strength Period. Therefore, additional pressure may be insufficient in the absence of a cement slurry design that properly addresses the Critical Gel Strength Period. 3) The proposed rule precludes the judicious use of low density pre-flushes to reduce ECD and minimize losses while cementing. 4) The proposed rule is not technically necessary. The entire purpose of API Standard 65-2, 2nd Edition, which is already incorporated into the regulations by reference, is to describe method(s) of isolating potential flow zones.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.421(f)	What are the casing and cementing requirements by type of casing string?	Casing type: Liners Casing requirements: If you use a liner as surface casing, you must set the top of the liner at least 200 feet above the previous casing/liner shoe. If you use a liner as an intermediate string below a surface string or production casing below an intermediate string, you must set the top of the liner at least 100 feet above the previous casing shoe. You may not use a liner as conductor casing.	Casing type: Liners Casing requirements: If you use a liner as surface casing, you must set the top of the liner at least 200 feet above the previous casing/liner shoe. If you use a liner as an intermediate string below a surface string or production casing below an intermediate string, you must set the top of the liner at least 100 feet above the previous casing shoe. You may not use a liner as conductor casing. A casing string whose top is above the mudline and that has been cemented back to the mudline will be not considered a liner.	This regulation leaves uncertainty regarding how casing would be treated in deepwater riserless operations. By providing the additional requirements that the top of the liner is above the mudline and that is cemented back to the mudline, BSEE's intent can still be met without creating an unintended side effect.
§250.423(a)	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 and cementing the casing string.	(a) You must ensure that the latching mechanisms or lock down mechanisms are engaged upon installation of each casing string.	The proposed language change does not define success or how it is measured.
§250.423(b)	What are the requirements for casing and liner installation?	(b) If you run a liner that has a latching mechanism or lock down mechanism, you must ensure that the latching mechanisms or lock down mechanisms are engaged upon successfully installing and cementing the liner.	2) 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 installation of the liner.	The proposed language change does not define success or how it is measured.
§250.428(b)	What must I do in certain cementing and casing situations?	If you encounter the following situation: (b) Need to change casing setting depths or hole interval drilling depth (for a BHA with an under-reamer, this means bit depth) more than 100 feet true vertical depth (TVD) from the approved APD due to conditions encountered during drilling operations, Then you must... Submit those changes to the District Manager for approval and include a certification by a professional engineer (PE) that he or she reviewed and approved the proposed changes.		PE certification should only be required in the event the change in depth drives a significant change in the cementing program (i.e. exposure of additional hydrocarbon zone, lost returns zone, etc)

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.428(c)	What must I do in certain cementing and casing situations?	If you encounter the following situation: (c) Have indication of inadequate cement job (such as lost returns, no cement returns to mudline or expected height, cement channeling, or failure of equipment), Then you must... (1) Locate the top of cement by: (i) Running a temperature survey; (ii) Running a cement evaluation log; or (iii) Using a combination of these techniques. (2) Determine if your cement job is inadequate. If your cement job is determined to be inadequate, refer to paragraph (d) of this section. (3) If your cement job is determined to be adequate, report the results to the District Manager in your submitted WAR.	If you encounter the following situation: (c) Have indication of inadequate cement job (such as unplanned lost returns, no cement returns to mudline, cement channeling, or failure of equipment), Then you must... (1) Locate the top of cement by: (i) Lift pressure analysis; (ii) Running a temperature survey; (iii) Running a cement evaluation log; 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.	In many cases, especially in deepwater, losses may be expected above the planned top of cement (TOC) which would not compromise the success of the job. Cement lift pressures are an industry recognized alternative to logs for determining TOC.
§250.428(d)	What must I do in certain cementing and casing situations?	If you encounter the following situation: (d) Inadequate cement job, Then you must... Take remedial actions. The District Manager must review and approve all remedial actions before you may take them, unless immediate actions must be taken to ensure the safety of the crew or to prevent a well-control event. If you complete any immediate action to ensure the safety of the crew or to prevent a well-control event, submit a description of the action to the District Manager when that action is complete. Any changes to the well program will require submittal of a certification by a professional engineer (PE) certifying that he or she reviewed and approved the proposed changes, and must meet any other requirements of the District Manager.	If you encounter the following situation: (d) Inadequate cement job, Then you must... Take remedial actions. The District Manager must review and approve all remedial actions before you may take them, unless immediate actions must be taken to ensure the safety of the crew or to prevent a well-control event. If you complete any immediate action to ensure the safety of the crew or to prevent a well-control event, submit a description of the action to the District Manager when that action is complete. Any changes to the casing or cement program that can impact the effectiveness of the barrier will require submittal of a certification by a professional engineer (PE) certifying that he or she reviewed and approved the proposed changes, and must meet any other requirements of the District Manager.	Recommend only changes that alter the effectiveness of the barrier need to be certified by a PE.
§250.462	What are the source control and containment requirements?	What are the source control and containment requirements? For drilling operations using a subsea BOP or surface BOP on a floating facility, you must have the ability to control or contain a blowout event at the sea floor.	What are the source control and containment requirements? For drilling operations using a subsea BOP or surface BOP on a floating facility, you must have the ability to control or contain a blowout event at the sea floor or approved alternate.	An equivalency for seabed source control and containment should be provided in the rule. The rule as written does not promote the development of alternative technologies which may be more effective than traditional responses.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.462(a)	What are the source control and containment requirements?	(a) To determine your required source control and containment capabilities you must do the following: (1) Consider a scenario of the wellbore fully evacuated to reservoir fluids, with no restrictions in the well. (2) Evaluate the performance of the well as designed to determine if a full shut-in can be achieved without having reservoir fluids broach to the sea floor. If your evaluation indicates that the well can only be partially shut-in, then you must determine your ability to flow and capture the residual fluids to a surface production and storage system.	(a) To determine your required source control and containment capabilities you must do the following: (1) Consider a scenario of the wellbore fully evacuated to reservoir fluids, with no restrictions in the well. (2) Evaluate the performance of the well as designed to verify that a full shut-in can be achieved without having reservoir fluids broach to the sea floor. (3) If your evaluation indicates that the well can only be partially shut-in, then you must determine your ability to flow and capture the residual fluids to a surface production and storage system.	Recommend rewording the regulation to place focus on designing for shut-in capability. Where possible, this should be the preferred approach to new well design. For cases where cap and flow capability is needed, provision must be maintained for capture and storage response measures.
§250.462(b)	What are the source control and containment requirements?	(b) You must have access to and ability to deploy Source Control and Containment Equipment (SCCE) necessary to regain control of the well. SCCE means the capping stack, cap and flow system, containment dome, and/or other subsea and surface devices, equipment, and vessels whose collective purpose is to control a spill source and stop the flow of fluids into the environment or to contain fluids escaping into the environment. This equipment must include, but is not limited to, the following: (1) Subsea containment and capture equipment, including containment domes and capping stacks; (2) Subsea utility equipment, including hydraulic power, hydrate control, and dispersant injection equipment; (3) Riser systems; (4) Remotely operated vehicles (ROVs); (5) Capture vessels; (6) Support vessels; and (7) Storage facilities.	(b) You must have access to and ability to deploy Source Control and Containment Equipment (SCCE) necessary to regain control of the well. SCCE means the capping stack, cap and flow system (where applicable as per 250.462(a)(3), containment dome (i.e. localized , non - pressurized , subsea fluids collection device) , or other subsea and surface devices, equipment, and vessels whose collective purpose is to control a spill source and stop the flow of fluids into the environment or to contain fluids escaping into the environment. Cap and flow systems (including containment domes) are not required for wells that are designed for shut-in on a full column of hydrocarbon. SCCE covers: (1) Subsea containment and capture equipment, including containment domes and capping stacks; (2) Subsea utility equipment, including hydraulic power, hydrate control, and dispersant injection equipment; (3) Riser systems; (4) Remotely operated vehicles (ROVs); (5) Capture vessels; (6) Support vessels; and (7) Storage facilities.	SCCE requirements should be specific to each well. Cap and Flow equipment should not be required for wells that have been specifically designed for shut-in on a full hydrocarbon column. Although infrastructure exists in the Gulf of Mexico for Cap and Flow, other regions would be placed at a significant disadvantage if dedicated flow capture and production systems need to be developed. This would also deter operators from focusing on design for Cap and Contain.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.462(c)	What are the source control and containment requirements?	(c) You must submit a description of your source control and containment capabilities to the Regional Supervisor and receive approval before BSEE will approve your APD, Form BSEE-0123. The description of your containment capabilities must contain the following: (1) Your source control and containment capabilities for controlling and containing a blowout event at the seafloor, (2) A discussion of the determination required in paragraph (a) of this section, and (3) Information showing that you have access to and ability to deploy all equipment required by paragraph (b) of this section.	(c) You must submit a description of your source control and containment capabilities to the Regional Supervisor and receive approval before BSEE will approve your APD, Form BSEE-0123. The description of your containment capabilities must contain the following: (1) Your source control and containment capabilities for controlling and containing a blowout event at the seafloor or approved alternate, (2) A discussion of the determination required in paragraph (a) of this section, and (3) Information showing that you have access to and ability to deploy all equipment required by paragraph (b) of this section.	Industry already submit the required documents with each permit (RP checklist). Does the Regional Containment Demonstration(RCD) satisfy this once approved? Retain flexibility for other options (i.e. pre-installed capping device for SPAR and TLPS, insitu burning and dispersants).
§250.462(d)	What are the source control and containment requirements?	(d) You must contact the District Manager and Regional Supervisor for reevaluation of your source control and containment capabilities if your: (1) Well design changes, or (2) Approved source control and containment equipment is out of service.	(d) You must contact the District Manager or Regional Supervisor for reevaluation of your source control and containment capabilities if your: (1) Well design or well conditions change such that a revised permit is required to drill and can impact the results of the well containment screening tool, or (2) Approved source control and containment equipment is out of service.	If geologic results are significantly different than what was planned for, operations should cease and a risk-based process should be implemented to manage work program risk to the lowest possible level. If BSEE's regional representatives are not satisfied that the risk justifies continuing operations then operations should be halted and the permit withdrawn.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.462(e)(1)	What are the source control and containment requirements?	Equipment (1) Capping stacks, Requirements, you must: (i) Function test all pressure holding critical components on a quarterly frequency (not to exceed 104 days between tests), Additional information: Pressure holding critical components are those components that will experience wellbore pressure during a shut-in after being functioned. Requirements, you must: (ii) Pressure test pressure holding critical components on a bi-annual basis, but not later than 210 days from the last pressure test. All pressure testing must be witnessed by BSEE and a BSEE- approved verification organization, Additional information: Pressure holding critical components are those components that will experience wellbore pressure during a shut-in. These components include, but are not limited to: all blind rams, wellhead connectors, and outlet valves. Requirements, you must: (iii) Notify BSEE at least 21 days prior to commencing any pressure testing.	Equipment (1) Capping stacks, Requirements, you must: (i) Function test all pressure holding critical components on a quarterly frequency (not to exceed 104 days between tests) or as otherwise approved by the Regional Supervisor for an alternative testing frequency. (ii) Pressure test pressure holding critical components on a bi-annual basis, but not later than 210 days from the last pressure test, or as otherwise approved by the Regional Supervisor for an alternative testing frequency . All pressure testing must be witnessed by BSEE and/or a verification organization, (iii) Notify BSEE at least 21 days prior to commencing any pressure testing. Additional information: Pressure holding critical components are those components that will experience wellbore pressure during a shut-in. These components include, but are not limited to: all blind rams, wellhead connectors, and outlet valves.	As data is collected testing frequency may have to be adjusted. As such, the regulations should allow regional supervisors to approve alternate testing frequencies. Further clarification is required on BSEE approved verification organizations, their scope and the associated accountability and liability they and BSEE assume through their direct engagement in the process.
§250.462(e)(2)	What are the source control and containment requirements?	Equipment: (2) Production Safety Systems used for flow and capture operations, Requirements, you must: (i) Meet or exceed the requirements set forth in 30 CFR 250.800-250.808, Subpart H, (ii) Have all equipment unique to containment operations available for inspection at all times.	Equipment: (2) Production Safety Systems used for flow and capture operations, Requirements, you must: (i) Meet the requirements set forth in 30 CFR 250.800-250.808, Subpart H, excluding equipment requirements that would be installed below the wellhead or that are not applicable to the cap and flow system. (ii) Have all equipment unique to containment operations available for inspection at all times.	30 CFR 250.800-250.808, Subpart H includes requirements for items below the wellhead which does not apply to source control (i.e. subsurface safety valves).
§250.462(e)(3)	What are the source control and containment requirements?	Equipment: (3) Subsea utility equipment, Requirements, you must: Have all equipment unique to containment operations available for inspection at all times. Additional information Subsea utility equipment includes, but is not limited to: hydraulic power sources, debris removal, hydrate control equipment, and dispersant injection equipment.	Equipment: (3) Subsea utility equipment, Requirements, you must: Have all equipment utilized uniquely for containment operations available for inspection at all times.	Clarification is required regarding the specific meaning of "available for inspection at all times".

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.518(e)	Tubing and wellhead equipment.	(e) Installed packers and bridge plugs, you must meet the following:		
§250.518(e)(1)	Tubing and wellhead equipment.	(1) All packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198)	(e) After the effective date of this regulation, permanently installed (as defined in the APD and/or APM) packers and bridge plugs must meet the following: (1) All packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198)	API 11D1 does not apply to temporary packers and bridge plugs which are commonly used in well servicing applications. The final regulation must account for these sensitivities.
§250.518(e)(2)	Tubing and wellhead equipment.	(2) During well completion operations, the production packer must be set at a depth that will allow for a column of weighted fluids to be placed above the packer that will exert a hydrostatic force greater than or equal to the force created by the reservoir pressure below the packer;	Delete 250.518(e)(2) and add revise 250.518(f) to read as follows: Your APD/APM must include a description and calculations explaining your production packer setting depth, packer fluid selection and planned annulus barriers.	This requirement would likely compromise well objectives, reservoir recovery, and add risk or cost in many situations. The perceived risk/benefit driving this new requirement is very limited and not necessary or warranted for broad application. A completion fluid column that exerts kill pressure does not guarantee killing the well in the event of packer or tubing leak. It may also result in greater loads on production casing or production tubing, reduced safety factors, increase well costs, reduced completion size, reduced production, and reduced well reliability. It is not possible for some artificial lift methods, particularly gas lifted wells and ESP's. It should also be noted that this new requirement and others related to packers may limit, not allow for, or not be applicable for tubingless completions (which can optimize reservoir recovery or add reserves by making uneconomic reserves economic).
§250.518(e)(3)	Tubing and wellhead equipment.	(3) The production packer must be set as close as practically possible to the perforated interval; and	Delete 250.518(e)(3) and add revise 250.518(f) to read as follows: Your APD/APM must include a description and calculations for how you determined the production packer setting depth and packer fluid selection.	Further definition and alignment is required on the phrase "as close as practically possible". Some completion tools/methods require a certain distance between top perf and packer. In the case of a short or small production liner, it may be highly desirable (improve well reliability and increase reservoir recovery) to place the production packer in the casing just above the production liner.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.518(e)(4)	Tubing and wellhead equipment.	(4) The production packer must be set at a depth that is within the cemented interval of the selected casing section.	Delete 250.518(e)(4) and add revise 250.518(f) to read as follows: Your APD/APM must include a description and calculations for how you determined the production packer setting depth and packer fluid selection.	This requirement may compromise well objectives, compromise optimum reservoir recovery, and may add risk or cost. In cases where a cement bond must be achieved via remedial operations there would be an increase in operational complexity and cost. The process requires perforating the primary well containment (production casing) and further additional steps are required to ensure the primary well containment has not been compromised following the squeeze operations (e.g., squeeze perforations should be tested both positive and negative, which can be difficult to achieve and establishing acceptance / rejection criteria is difficult). Often times an additional production packer is set above the squeeze perforations in order to ensure the exposed perforations do not leak later in life. Such complications should and can be avoided with prudent well design. A number of other planned situations would be prohibited by the proposed rule, such as situations when it is preferable to have an uncemented production liner lap and set the production packer within the lap, or when using electric submersible pumps (or other pump) at intermediate to shallow depths in the well.
§250.619(e)	Tubing and wellhead equipment.	(e) If you pull and reinstall packers and bridge plugs, you must meet the following:		See comments for 250.518(e), same recommendations apply for 250.619(e).
§250.619(e)(1)	Tubing and wellhead equipment.	(1) All packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198);		See comments for 250.518(e), same recommendations apply for 250.619(e).
§250.619(e)(2)	Tubing and wellhead equipment.	(2) The production packer must be set at a depth that will allow for a column of weighted fluids to be placed above the packer during well completion operations that will exert a hydrostatic force greater than or equal to the force created by the reservoir pressure below the packer;		See comments for 250.518(e), same recommendations apply for 250.619(e).
§250.619(e)(3)	Tubing and wellhead equipment.	(3) The production packer must be set as close as practically possible to the perforated interval; and		See comments for 250.518(e), same recommendations apply for 250.619(e).
§250.619(e)(4)	Tubing and wellhead equipment.	(4) The production packer must be set at a depth that is within the cemented interval of the selected casing section.		See comments for 250.518(e), same recommendations apply for 250.619(e).

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.703	What must I do to keep wells under control?	You must take necessary precautions to keep wells under control at all times, including:		
§250.703(f)	What must I do to keep wells under control?	(f) Use equipment that has been designed, tested, and rated for the most extreme service conditions to which it will be exposed while in service.	(f) Select equipment that is designed and rated for the anticipated conditions to which it will be exposed while in service.	The requirement for equipment to have been "designed, tested and rated for the most extreme service conditions to which it will be exposed while in service" is ambiguous. Recommend using the term "anticipated conditions" vs. "extreme conditions". If extreme load survival is desired for certain pieces of equipment it should be justified and treated as a separate requirement as product operating envelopes do not usually extend to cover the full range of low likelihood, extreme scenarios. Unnecessary over-design of equipment can decrease overall system reliability and introduce additional risk. As an example, increased design loads for BOPs would drive larger material forgings (increasing manufacturing and machining complexity) and add to overall stresses and fatigue loads experienced by wellheads and casing strings.
§250.711(a)	What are the requirements for well-control drills?	(a) Timing of drills. You must conduct each drill during a period of activity that minimizes the risk to operations. The timing of your drills must cover a range of different operations, including drilling with a diverter, on-bottom drilling, and tripping. The same drill may not be repeated consecutively.	(a) Timing of drills. You must conduct each drill during a period of activity that minimizes the risk to operations. The timing of your drills must cover a range of different operations, including drilling with a diverter, on-bottom drilling, and tripping and be appropriate for current operations.	The proposal is overly prescriptive as written. Should enable flexibility to ensure drills are relevant for the operations being conducted. Repetition of certain drills may be necessary due to the criticality of upcoming relevant operations or as focused areas of improvement.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.712(a)	What rig unit movements must I report?	(a) You must report the movement of all rig units on and off locations to the District Manager using Form BSEE-0144, Rig Movement Notification Report. Rig units include MODUs, platform rigs, snubbing units, wire-line units used for non-routine operations, and coiled tubing units. You must inform the District Manager 72 hours before: (1) The arrival of a rig unit on location; (2) The movement of a rig unit to another slot. For movements that will occur less than 72 hours after initially moving onto location (e.g., coiled tubing and batch operations), you may include your anticipated movement schedule on Form BSEE-0144; or (3) The departure of a rig unit from the location.	(a) Prior to commencing operations and at the completion of operations, you must report the movement of all drilling units on and off drilling locations to the District Manager. This includes both MODU and platform rigs. (1) You must inform the District Manager 48 hours before: (i) Prior to commencement of operations, the arrival of an MODU on location; and (ii) at the completion of operations, the departure of an MODU from the location. (2) You must inform the District Manager 24 hours before: (i) The movement of a platform rig to a platform; (ii) The movement of a platform rig to another slot; and (iii) The movement of an MODU to another slot.	Note that this change in the reporting requirement from 24 hour notice to 72 hour notice would likely result in increased inaccurate estimates of operational moves of various unit and rig types due to the potential for operational plans, schedules or sequences to change over these extended time periods. This is likely to result in multiple reporting adjustments being made to BSEE during the anticipated reporting periods. Recommend that this reporting notice be reduced to 48 hours versus the currently proposed 72 hour timeframe. 48 hours is consistent with USCG notification for MODUs.
§250.712(d)	What rig unit movements must I report?	(d) Prior to resuming operations after stacking, you must notify the appropriate District Manager of any construction, repairs, or modifications associated with the drilling package made to the MODU or platform rig;	(d) Prior to resuming operations after stacking, you must notify the appropriate District Manager of any construction, repairs, or modifications made to a MODU or platform rig associated with the BOP and/or well control system, marine or life safety systems, sationkeeping systems, lifting and hoisting equipment or the rig's primary structure.	The requirement to notify the District Manager of "any" construction, repairs or modifications associated with the drilling package is ambiguous. Recommend that BSEE define what type of construction, modification or repair they would like to receive notification of.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.713(a)	What must I provide if I plan to use a mobile offshore drilling unit (MODU) or lift boat for well operations?	(a) Fitness requirements. Information and data to demonstrate the capability to perform at the proposed location. This information must include the most extreme environmental and operational conditions that the unit is designed to withstand, including the minimum air gap necessary for both hurricane and non-hurricane seasons. If sufficient environmental information and data are not available at the time you submit your APD or APM, the District Manager may approve your APD or APM but require you to collect and report this information during operations. Under this circumstance, the District Manager has the right to revoke the approval of the APD or APM if information collected during operations shows that the MODU or lift boat is not capable of performing at the proposed location.	Propose adding text: In some cases, the District Manager may accept environmental criteria based on regional data that was developed by a knowledgeable metocean specialist.	The potential requirement to collect environmental data is ambiguous. The data collected would be of little benefit to the MODU or lift boat on location that is collecting the data, and it could be at risk if it were truly "unsuitable" for the site conditions. Recommend that suitability for the location be assessed by applying conservative environmental criteria based on the judgment of a knowledgeable metocean specialist. If the uncertainty in metocean criteria can not be resolved with conservative criteria assumptions, the environmental data should be gathered before mobilizing a MODU or lift-boat to the location.
§250.713(b)	What must I provide if I plan to use a mobile offshore drilling unit (MODU) or lift boat for well operations?	(b) Foundation requirements. Information to show that site-specific soil and oceanographic conditions are capable of supporting the proposed MODU or lift boat. If you provided sufficient site-specific information in your EP, DPP, or DOCD submitted to BOEM, you may reference that information. The District Manager may require you to conduct additional surveys and soil borings before approving the APD or APM if additional information is needed to make a determination that the conditions are capable of supporting the MODU, lift boat, or equipment installed on a subsea wellhead. For moored rigs, you must submit a plat of the rigs' anchor pattern approved in your EP, DPP, or DOCD in your APD or APM.	Propose adding text: In some cases, the District Manager may accept lower and upper bound soil properties based on regional soil data and developed by a knowledgeable geotechnical engineer.	Recommend that it be noted that it some applications (determination of MODU anchor capacity, for instance) it is acceptable practice to utilize conservatively developed lower and upper bound soil properties based on nearby of regional data that is developed by a knowledgeable geotechnical specialist in lieu of site specific soil boring(s).

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.714	Do I have to develop a dropped objects plan?	If you use a floating rig unit in an area with subsea infrastructure, you must develop a dropped objects plan and make it available to BSEE upon request. This plan must be updated as the infrastructure on the seafloor changes. Your plan must include:		Concur that "safe handling zones" should be identified and that a dropped objects plan should be developed when operating near infrastructure. Do not agree that modeling a potential dropped object's path significantly reduces the risk associated with a dropped object due to (1) the numerous variables and uncertain site conditions involved with such an analysis; (2) the rig path to a drill center will require close proximity to infrastructure that can't be avoided; (3) if the largest loads (e.g. BOP and riser, subsea trees, etc.) are dropped, it is impractical to protect the infrastructure structurally; and (4) the model does nothing to materially improve the field operations and creates additional work and expense and what could be a "false sense of security". Recommend that the requirement for modeling dropped objects be removed. Recommend that the dropped object mitigation plan be focused on (1) designing infrastructure, particularly the more fragile components, to be protected from smaller objects; (2) that lifting and hoisting equipment, running and handling tools, etc. be routinely inspected; (3) that work plans, tool box talks, and procedures used to conduct operations highlight and address dropped object potential; (4) that the SIMOPS plan addresses communication with the infrastructure owner's personnel (commonly the production operators); and (5) that communications to the infrastructure owner's personnel are made pre and post lift to that they can be engage as required and quickly mitigate the consequences of a dropped object.
§250.714(e)	Do I have to develop a dropped objects plan?	(e) Any additional information required by the District Manager.	(e) Any additional information required by the District Manager that could be reasonably expected to have a significant impact on overall operational risk.	Requirement is ambiguous and should be clarified
§250.715	Do I need a global positioning system (GPS) for MODUs and jack-ups?	All jack-up and moored MODUs must have a minimum of two functioning GPS transponders at all times, and you must provide to BSEE real-time access to the GPS data prior to each hurricane season.		Real time access to transponder data needs to be clarified and quantified.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.721(a)(3)	What are the requirements for pressure testing casing and liners?	Casing type: (3) Surface, Intermediate, and Production, Minimum test Pressure: 70 percent of its minimum internal yield.		Pressure test requirement should focus on ensuring integrity of the string. Recommend minimum casing test pressure is linked to formation integrity that it seals, i.e. Minimum test pressure is the lesser of 500 psi above estimated shoe leak off, or 70 percent of minimum internal yield along the length of the casing.
§250.721(b)	What are the requirements for pressure testing casing and liners?	(b) You must test each drilling liner and liner-lap to a pressure at least equal to the anticipated leak off pressure of the formation below that liner shoe, or subsequent liner shoes if set. You must conduct this test before you continue operations in the well.	(a) You must test each drilling liner (and liner-top) to a pressure at least equal to the anticipated pressure to which the liner will be subjected during the formation pressure-integrity test below that liner shoe, or subsequent liner shoes if set.	Testing of the liner-lap is not always possible. The liner-top can be tested to confirm integrity.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.721(e)	What are the requirements for pressure testing casing and liners?	(e) If you plan to produce a well, you must: (1) For a well that is fully cased and cemented, pressure test the entire well to maximum anticipated shut-in tubing pressure before perforating the casing or liner; or (2) For an open-hole completion, pressure test the entire well to maximum anticipated shut-in tubing pressure before you drill the open-hole section.	(e) If you plan to produce a well, you must: (1) For a well that is fully cased and cemented, pressure test the entire well to maximum anticipated shut-in tubing pressure, but not to exceed 70% of burst rating, before perforating the casing or liner; or (2) For an open-hole completion, pressure test the entire well to maximum anticipated shut-in tubing pressure, but not to exceed 70% of burst rating, before you drill the open-hole section.	The proposed language to "pressure test the entire well to maximum anticipated shut-in tubing pressure" is not clearly defined and subject to interpretation. It is not clear if "anticipated shut-in tubing pressure" is with full column of HC or after perforating with an underbalanced fluid. If the context is with full column of HC, it is problematic to implement this when the fluid in the well at time of pressure test is different density than the planned completion fluid. In this situation, the proposed new rule applied literally could require multiple pressure tests with a test packer set at different depth for each test. This could add risk due to multiple pressure tests, inducing multiple stress cycles on the casing and the cement to casing bond, increase the chance of casing failure later in life of the well, and/or increase chance of forming a microannulus. The proposed language would also very likely result in higher test pressure for many wells, particularly high pressure wells, and this would induce greater stress on the casing and casing to cement bond, further increase the chance of casing failure later in life of well, and/or increase the chance of forming a microannulus. Besides the potential unintended negative consequences mentioned above, the historical requirement to test to maximum anticipated SITP, but not to exceed 70% of burst rating, has proven effective and should be continued (the 70% burst rating limit, as practiced, prevents the potential issues mentioned above).
§250.721(g)	What are the requirements for pressure testing casing and liners?	(g) You must perform a negative pressure test on all wells that use a subsea BOP stack or wells with mudline suspension systems.		
§250.721(g)(1)	What are the requirements for pressure testing casing and liners?	(1) You must perform a negative pressure test on your final casing string or liner. This test must be conducted after setting your second barrier just above the shoe track but prior to conducting any completion operations.	If hydrocarbons are present, you must perform a negative pressure test on your final casing string or liner. This test must be conducted after setting your second barrier just above the shoe track but prior to conducting any completion operations.	The requirement to perform a negative test on the final casing string or liner should only apply if hydrocarbons are present.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.721(g)(7)	What are the requirements for pressure testing casing and liners?	(7) You must have two barriers in place, as described in § 250.420(b)(3), at any time and for any well, prior to performing the negative pressure test.	If hydrocarbons are present, you must have two barriers in place, as described in § 250.420(b)(3), prior to performing the negative pressure test.	The requirement to have two barriers in place prior to performing a negative test should only apply if hydrocarbons are present.
§250.722	What are the requirements for prolonged operations in a well?	If wellbore operations continue within a casing or liner for more than 30 days from the previous pressure test or BSEE approved verification of the well's casing or liner, you must:		
§250.722(a)	What are the requirements for prolonged operations in a well?	(a) Stop operations as soon as practicable, and evaluate the effects of the prolonged operations on continued operations and the life of the well. At a minimum, you must: (1) Evaluate the well's casing with either a pressure test, caliper tool, or imaging tool. On a case-by-case basis the District Manager may require a specific method of evaluation; and (2) Report the results of your evaluation to the District Manager and obtain approval of those results before resuming operations. Your report must include calculations that show the well's integrity is above the minimum safety factors.	(a) Stop operations as soon as practicable, and evaluate the effects of the prolonged operations on continued operations and the life of the well. At a minimum, you must: (1) Evaluate the well's casing with either a pressure test, caliper tool, or imaging tool. On a case-by-case basis the District Manager may require a specific method of evaluation; and (2) Report the results of your evaluation to the District Manager and obtain approval of those results before resuming operations. If an imaging tool or caliper is used, then your report must include calculations that show the well's integrity is above the minimum safety factors.	Calculations that show a well's integrity is above the minimum safety factors cannot be performed for a casing pressure test.
§250.724(a)	What are the real-time monitoring requirements?	(a) When conducting well operations with a subsea BOP or surface BOP on a floating facility, or when operating in an HPHT environment, you must, within 3 years of publication of the final rule, gather and monitor real-time well data using an independent, automatic, and continuous monitoring system capable of recording, storing, and transmitting all aspects of; (1) The BOP control system; (2) The well's fluid handling systems on the rig; and (3) The well's downhole conditions with the bottom hole assembly tools (if any tools are installed).	(a) When conducting well operations with a subsea BOP or surface BOP on a floating facility, or when operating in an HPHT environment, you must gather and monitor real-time well data using a system capable of recording, storing, and transmitting data as identified in a Real Time Monitoring Plan. Within 3 years of publication of the final rule, the Real Time Monitoring Plan must address the (1) the fluid circulating system and (2) bottom hole tools. Within 5 years of publication of the final rule, the Real Time Monitoring Plan must address the BOP status.	To ensure real time monitoring can be effective, associated regulations should be risk-based and enable fit-for-purpose proposals from individual Operators. As written, the prescriptive requirements are vague and do not provide sufficient detail to enable Operators to understand and assess what the requested minimum requirement (i.e. what does "well's fluid handling system" encompass? how many sensors? where? what resolution / frequency?); a risk-based Real Time Monitoring Plan requirement resolves these complications.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.724(b)	What are the real-time monitoring requirements?	(b) You must immediately transmit these data as they are gathered to a designated onshore location during operations where they must be monitored by qualified personnel who must be in continuous contact with rig personnel during operations. After operations, you must preserve and store this data at a designated location for recordkeeping purposes as required in §§ 250.740 and 250.741. You must designate the location where the data will be stored and monitored during operations in your APD or APM. The location and the data must be made accessible to BSEE upon request.	(b) During well operations, real-time data must be monitored by qualified personnel and transmitted to a designated onshore location, as defined in the Real Time Monitoring Plan. Where defined in the Real Time Monitoring Plan, the onshore monitoring personnel must have the capabilities to communicate with rig personnel during operations. After operations, the data must be preserved and stored at a designated location for recordkeeping purposes as required in §§ 250.740 and 250.741. The location and the data must be made accessible to BSEE upon request.	Current proposal to "immediate transmit" and "be in continuous contact" is ambiguous. The proposed revised wording would meet the intent and enable fit-for-purpose application depending on the operation at the time.
§250.724(c)	What are the real-time monitoring requirements?	(c) If you lose any real-time monitoring capability during operations covered by this section, you must immediately notify the District Manager. The District Manager may require other measures until real-time monitoring capability is restored.	(c) The Real Time Monitoring Plan must define a protocol if real-time monitoring capabilities are lost during operations covered by this section.	There are several situations where loss of real-time monitoring should not require engagement with the District Manager (i.e. picking up or laying down drill pipe with a secure well) and the Real Time Monitoring Plan could address these. Furthermore, a Real Time Monitoring Plan could detail what planning and preparation can be put in place to enable operations to continue without active remote real time monitoring in anticipation of potential issues (i.e. weather interference, bandwidth limitations, etc).

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.730(a)	What are the general requirements for BOP systems and system components?	(a) You must design, install, maintain, inspect, test, and use the BOP system and system components to ensure well-control. The working-pressure rating of each BOP component must exceed MASP as defined for the operation. For a subsea BOP, the MASP must be taken at the mudline. The BOP system includes the BOP stack, control system, and any other associated system(s) and equipment. The BOP system and individual components must be able to perform their expected functions and be compatible with each other.	(a) You must select, install, maintain, inspect, test, and use the BOP system and system components to ensure well-control. The working-pressure rating of each BOP component from uppermost ram to wellhead connector 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.	Manufacturer's design and build equipment. Operators and Equipment Owners (Rig Contractors) select equipment. Annular BOPs are currently limited to a maximum rated working pressure limit of 10k psi. Ram preventers could be 15k to 20k psi RWP and are used for high pressure (MASP type) shut-in situations. Annular BOP's are typically used for initial shut in on a flowing well as they are built to throttle the wellbore closed under flowing conditions. Most operators utilize ram type preventers if shut in pressures on the annular preventer reach 1.5 to 3.5k psi. Annular preventers are typically one to two API RWP sizes below ram preventer RWP. Thus, on a subsea BOP with 15k psi ram preventers, annular preventers will typically be rated to 10k psi RWP but could be as low as 5k psi RWP. Some 10k psi RWP annulars that are special built to allow stripping 6-5/8" tool joints are derated to 5k psi when modified. It is not technologically feasible to design and manufacture 15k psi RWP annulars in the near term. Thus, if annular preventers are not excluded from this proposed rule, industry would not be able to meet the regulation. Limit this proposed regulation to lower stack components including and below the uppermost ram.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.730(a)	What are the general requirements for BOP systems and system components?	(a) ..... Each ram (excluding casing shear/supershear) must be capable of closing and sealing the wellbore at all times, including under flowing conditions as defined for the operation and specific well conditions, without losing ram closure time and sealing integrity due to the corrosiveness, volume, and abrasiveness of any fluids in the wellbore that you may encounter. Your BOP system must meet the following requirements:	(a) ..... Each BOP system (excluding casing shear/supershear) must be capable of closing and sealing the wellbore at all times. Your BOP system must meet the following requirements:	As interpreted, the proposed regulation could require each ram to close and seal on a worse case discharge type event. If this interpretation is incorrect, then BSEE clarification to the proposed rule should be provided. BOP systems are capable of systematically shutting in a well by typically closing an annular preventer as the front line defense to stop a flowing well. After closing the annular, ram preventer(s) can then be closed as required during a no flow condition. Annular preventers have more seal elastomer than ram type preventers and are built for shutting in on a variety of flowing conditions, working pipe, stripping pipe, etc. Historically, industry has demonstrated the capability to successfully seal the wellbore under a variety of flowing conditions using a combination of annular and ram type preventers. Many flow stream variables would complicate any effort to define flow rates that a ram could be expected to close in "at all times". Emphasis should be placed on early detection and timely shut in. Ram preventers used in capping stacks have a flow diverter spool installed below them to prevent elastomer damage to the ram while closing on a high volume flow stream. It is not realistic to expect a drilling BOP ram preventer to close and seal on a high flow rate well stream but the BOP system in its entirety (using annulars and rams) is capable of shutting in on a high flow rate stream. The goal should be for the BOP system to reliably shut-in the well under reasonably anticipated flowing conditions. Understanding and effectively addressing this issue will require engagement with technical experts from operators, rig contractors, OEMs and regulatory bodies.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.730(a)(1)	What are the general requirements for BOP systems and system components?	(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.		This provision should be dropped. API Standard 53 was agreed by industry but the proposed rule obfuscates the interpretation of the standard; recommend that API Standard 53 be applied in it's entirety which was developed by industry SME's (including BSEE representation) and incorporates the best practices and recommendations of industry. The proposed rules that conflict with Standard 53 lack technical justification and basis to become a regulation. BSEE should provide industry SME's with an explanation and justification on each of the incremental proposals. With regards to dated references, only the relevant provisions of those references apply. The applicable editions of dated references should be those in effect at the date of manufacture of the specific equipment.
§250.730(a)(2)	What are the general requirements for BOP systems and system components?	(2) The following industry standards (all incorporated by reference in § 250.198): (i) ANSI/API Spec. 6A; (ii) ANSI/API Spec. 16A; (iii) ANSI/API Spec. 16C; (iv) API Spec. 16D; and (v) ANSI/API Spec. 17D.		See comments for 250.198 regarding use of API Standard 53 and it's specific sub references. Reference API 53 in its entirety with regards to 6A, 16A, 16C, 16D, and 17D, such that only the relevant provisions of those references apply. The editions of API 6A, 16A, 16C, 16D, and 17D should be those that were in effect at the date of manufacture of the specific equipment.
§250.730(a)(3)	What are the general requirements for BOP systems and system components?	(3) For surface and subsea BOPs, the pipe and variable bore rams installed in the BOP stack must be capable of effectively closing and sealing on the tubular body of any drill pipe, workstring, and tubing in the hole under MASP, as defined for the operation, with the proposed regulator settings of the BOP control system.	(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, work string, and tubing (excluding control lines, flat packs, etc.).	It was already established in section 250.730(a) that the BOP, including pipe and variable bore rams, be of RWP greater than MASP. MASP does not need to be repeated in every subsection. The statement regarding the regulator setting should also be removed as it is part of the control system described in 250.730(a). BSEE should clarify the sentence structure of this proposed requirement. Closing a ram preventer on tubing and control lines, flat packs, etc. is not currently achievable, nor is it a realistic expectation for the near future. If it is BSEE's expectation that ram preventers be capable of sealing in this condition, this regulation would not be possible to meet and industry would be shut down in the Gulf of Mexico.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.730(b)	What are the general requirements for BOP systems and system components?	(b) You must design, fabricate, maintain, and repair your BOP system according to the requirements contained in this subpart, OEM recommendations unless otherwise directed by BSEE, and recognized engineering practices. The training and qualification of repair and maintenance personnel must meet or exceed any OEM training recommendations unless otherwise directed by BSEE.	You must select, maintain, and repair your BOP system according to the requirements contained in this subpart, API Standard 53, and OEM recommendations unless otherwise directed by BSEE. The training and qualification of repair and maintenance personnel must meet the requirements of equipment owner's SEMS as dictated by CFR, Part 250, Subpart S unless otherwise directed by BSEE.	Operators and Rig Contractors (Equipment Owners) do not design and fabricate BOP equipment. OEM's design and fabricate, operator and rig contractors select, maintain and repair. OEM's do not presently publish training, qualification, and maintenance recommendations for equipment owner's to consider for training of their repair and maintenance personnel. Equipment owners (rig contractors) are already establishing standards per the SEMS regulation. Definition of OEM may be problematic. Is it the component manufacturer or the system supplier? The OEM purchases parts and components of the BOP from different suppliers. For instance, a shuttle valve may be manufactured by a subcontractor of the OEM. So, if the proposed rule implies that equipment owners service and maintenance personnel must receive training from subcontractors of the OEM before they can repair a shuttle valve, this is not a workable rule..
§250.730(c)	What are the general requirements for BOP systems and system components?	(c) You must follow the failure reporting procedures contained in API Standard 53, ANSI/API Spec. 6A, and ANSI/API Spec 16A, and:	(c) You must follow the failure reporting procedures contained in API Standard 53 (Operating Standard) and in ANSI/API Spec. 6A, and ANSI/API Spec 16A, (Manufacturing Standards) and:	BSEE needs to provide guidelines on the intended use for referencing these standards API Specification 6A and 16A references should not be identified as the qualifying reference as they are manufacturing related failure reporting methods. Standard 53 is an operational document.
§250.730(c)(1)	What are the general requirements for BOP systems and system components?	(1) You must provide a written report of equipment failure to the manufacturer of such equipment within 30 days after the discovery and identification of the failure.	(1) The equipment owner, with copy to the Operator, must ensure a written report of equipment failure is provided to the manufacturer of such equipment within 30 days after the discovery and identification of the failure. A failure is defined as the inability of the equipment to function or perform as required.	The equipment owner should be responsible for providing a written report of an equipment failure, if one is required. The Operator should be advised that the report was submitted. The definition of failure, provided in the recommended text, should be adopted throughout the proposed rules.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.730(c)(2)	What are the general requirements for BOP systems and system components?	(2) You must ensure that an investigation and a failure analysis are initiated within 60 days of the failure to determine the cause of the failure. If the investigation and analysis are performed by an entity other than the manufacturer, you must ensure that the manufacturer receives a copy of the analysis.	(2) The equipment owner must ensure that an investigation is initiated within 60 days of the failure to determine the cause of the failure. If the investigation is performed by an entity other than the manufacturer, the equipment owner must ensure that the manufacturer receives the results of the investigation. The investigation should be completed per a schedule agreed by the equipment owner and parties involved.	The equipment owner should be responsible for initiating an investigation and failure analysis. The proposed rule does not address the timing for completion of the investigation. The timing for completion of the investigation should be aligned with the nature of the failure and the complexity of the investigation and agreed by the equipment owner and the investigators.
§250.730(c)(3)	What are the general requirements for BOP systems and system components?	(3) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed, or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such notice or change, report the design change or modified procedures in writing to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; HE 3314; 45600 Woodland Road, Sterling, Virginia 20166.	(3) If the equipment manufacturer/owner notifies the equipment owner that it has changed the design, operating or repair procedures as a result of the failure reference in § 250.730(c)(1) , then equipment owner must, within 30 days of such notice or change, report the design change or modified procedures in writing to the District Supervisor; Bureau of Safety and Environmental Enforcement and the Operator.	The equipment manufacturer should notify the equipment owner if the manufacturer has changed the design of the equipment that failed, or if operating or repair procedures have changed as a result of a failure. (Note: design or procedure changes by the manufacturer don't necessarily have to be due to a failure.) The equipment owner should be responsible for notifying the Operator and BSEE (as required). This should be addressed under SEMS requirements (MOC); new version of API Specification 16A is aligned with Standard 53. Question why this report is being sent to HQ office instead of the District Supervisor as the standard path listed in this rulemaking. Clarify which entity is required to notify BSEE (e.g., contractor or operator involved in the original failure).
§250.730(d)	What are the general requirements for BOP systems and system components?	(d) If you plan to use a BOP stack manufactured after the effective date of this regulation, you must use one manufactured pursuant to an API Spec. Q1 (as incorporated by reference in § 250.198) quality management system. Such quality management system must be certified by an entity that meets the requirements of ISO 17011.	(d) If you plan to use BOP equipment and components manufactured after the effective date of this regulation, they must be manufactured pursuant to API Spec. Q1 (as incorporated by reference in § 250.198) and shall be API-monogrammed.	ISO 17011 is an incorrect reference. ISO 17021 is the correct reference that should be applied to organizations which certify that quality management systems meet the requirement of a particular reference. API Q1 9th edition is the correct edition. ANSI/API Q1 8th edition is no longer available from ANSI. There is no API standard for a BOP stack. Spec. Q1 would apply only to the individual components.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.731(c)	What information must I submit for BOP systems and system components?	You must submit: (c) Certification by a BSEE-approved verification organization, Including: Verification that: (1) Test data clearly demonstrates the shear ram(s) will shear the drill pipe at the water depth as required in § 250.732; (2) The BOP was designed, tested, and maintained to perform at the most extreme anticipated conditions; and (3) The accumulator system has sufficient fluid to function the BOP system without assistance from the charging system.	You must submit: Certification and verification that: (1) Actual cut and seal test data and/or supporting engineering calculations clearly demonstrate that the shear ram(s) will shear the drill pipe at the water depth as required in § 250.732; (2) The BOP was designed, tested, and maintained to perform at the anticipated conditions; and (3) The accumulator systems shall be in accordance with API Standard 53 guidelines.	"Test data" implies that a shearing test must be provided for each configuration. Clarification of BSEE's intent is requested. There is uncertainty with BSEE's statement stipulating "to perform at the most extreme anticipated conditions". We request that BSEE clarify the meaning of this statement. Is this a worst case discharge type event or a more typical kick type event? Shearing and sealing on flowing wells at worst case discharge rates is not a typical drilling BOP shut in scenario. In the vast majority of well kick shut in situations, the annular preventer is closed first on a drilling BOP to "throttle" the well flow down until the annular element fully closes and stops the well flow. At that time, pipe rams and shear rams can be used as required to safely secure or intervene on the well. Minimizing the amount of kick taken into the wellbore is crucial and BSEE emphasis should be on early detection and correct shut in procedures. Qualifying BOP components under flowing conditions is not currently part of the manufacturer's design criteria and there is no protocol to do so. If this proposed regulation becomes law, every BOP currently in use would not meet the regulation and the OEM would not be able to provide supporting documentation that a BOP component will close and seal on every conceivable well flow condition. BAVOs don't currently exist. This is a potential bottleneck.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.731(d)	What information must I submit for BOP systems and system components?	You must submit: (d) Additional certification by a BSEE-approved verification organization, if you use a subsea BOP, a BOP in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility. Including: Verification that: (1) The BOP stack is designed for the specific equipment on the rig and for the specific well design; (2) The BOP stack has not been compromised or damaged from previous service; and (3) The BOP stack will operate in the conditions in which it will be used.	You must submit: Additional certification, if you use a subsea BOP, a BOP in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility. Including: Verification that: (1) The BOP stack is suitable for use with the specific equipment on the rig and for the specific well requirements; (2) The BOP stack has not been compromised or damaged from previous service; and (3) The BOP stack will operate in the anticipated conditions for which it will be used.	BSEE's statement that BOP stacks are "designed" for the specific equipment on a rig is not correct for subsea operations and most surface BOP's. It is just the opposite. The specific well control equipment on the rig is designed to meet the RWP conditions of the BOP system in use. The BOP is selected based on RWP that is greater than the maximum anticipated wellhead pressure for the well program. "Suitable" is a better fitting word. BAVOs don't currently exist. This is a potential bottleneck.
§250.731(f)	What information must I submit for BOP systems and system components?	You must submit: (f) Certification stating that the Mechanical Integrity Assessment Report required in § 250.732(d) has been submitted within the past 12 months for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility.	You must submit: (f) Certification stating that the BOP and Well Compatibility Certificate, as required in an APD/APM, has been submitted to the BSEE District Manager within the past 12 months.	This is understood to be an affirmation that the mechanical integrity assessment report is a current and valid report.
§250.732	What are the BSEE-approved verification organization requirements for BOP systems and system components?		All of section 250.732 references to BSEE approved verification organizations should be removed/deleted.	Numerous issues are generated with the proposal for BSEE Approved Verification Organizations (BAVOs). Any rigs that work overseas would be adversely impacted as they would be unable to meet the requirement as written of being "monitored during its entire lifecycle" and recertification may be uneconomic and technically impractical to achieve. If implemented, further clarification will be required on the responsibility, accountability and liability BSEE assume as a result of enforcing the use of select verification organizations that BSEE officially certify. Detailed comments are provided below to highlight our concerns with the respective sub-components of 250.732.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.732(a)	What are the BSEE-approved verification organization requirements for BOP systems and system components?	(a) The BSEE will maintain a list of BSEE-approved verification organizations that you may use. For an organization to become a BSEE approved verification organization, it must submit the following information to the Chief, Office of Regulatory Programs: Bureau of Safety and Environmental Enforcement: 45600 Woodland Road, Sterling, Virginia, 20166, for BSEE review and approval:		§250.732(a) should not go into effect until at least 12 months after the initial BSEE-approved Verification Organization list is published. There is no current process or protocol for BSEE to use to establish and maintain such certifications and the time required to get this done and maintain sufficient capacity should not be underestimated. It is imperative that BSEE provides an adequate number of adequately staffed, and equally qualified, BSEE approved verification organizations to meet the industry demands in a timely manner. Thus, BSEE should have well defined qualification criteria and a process for verification organization periodic audit. Industry is concerned that there are not an adequate number of people with the required skills to perform all the verifications within the proposed rule enforcement timing and it would take time for industry to enhance its capabilities. It is also imperative that the industry be allowed to use any available approved verification organization (e.g., not be required to use the one who performed the prior verification).
§250.732(a)(1)	What are the BSEE-approved verification organization requirements for BOP systems and system components?	(1) Previous experience in verification or in the design, fabrication, installation, repair, or major modification of BOPs and related systems and equipment;		Proposed organizations should have experience in verification. BAVOs with only previous design, fabrication, installation, etc experience and no verification experience would not have the skill sets necessary for proper verification and certification of equipment.
§250.732(a)(2)	What are the BSEE-approved verification organization requirements for BOP systems and system components?	(2) Technical capabilities;		BSEE should have criteria that defines the minimum acceptable technical capabilities for an approved verification organization.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.732(a)(3)	What are the BSEE-approved verification organization requirements for BOP systems and system components?	(3) Size and type of organization;		BSEE should ensure that an approved verification organization has adequate staff (e.g., management, technical and administrative staff, and field surveyors) to complete the expected verification requirements in an efficient manner. A verification organization should have staff to manage more than a single verification simultaneously.
§250.732(a)(4)	What are the BSEE-approved verification organization requirements for BOP systems and system components?	(4) In-house availability of, or access to, appropriate technology. This should include computer programs, hardware, and testing materials and equipment;		BSEE should have criteria that defines the minimum acceptable technical capabilities for an approved verification organization.
§250.732(a)(6)	What are the BSEE-approved verification organization requirements for BOP systems and system components?	(6) Previous experience with BSEE requirements and procedures; and		While it is preferred that an approved verification organization has prior experience with BSEE requirements and procedures it may not be mandatory if the organization has experience dealing with other regulatory regimes in a similar capacity.
§250.732(a)(7)	What are the BSEE-approved verification organization requirements for BOP systems and system components?	(7) Any additional information that may be relevant to BSEE's review.		An approved verification organization should have offices and staff located on the gulf coast of the United States to allow for an efficient and timely engagement with equipment owners and Operators.
§250.732(b)	What are the BSEE-approved verification organization requirements for BOP systems and system components?	(b) Prior to beginning any operation requiring the use of any BOP, you must submit verification by a BSEE-approved verification organization and supporting documentation as required by this paragraph to the appropriate District Manager and Regional Supervisor.		"BAVOs" do not currently exist which may result in delays/shutdowns upon the effective date of this rule.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.732(b)(1)i	What are the BSEE-approved verification organization requirements for BOP systems and system components?	You must submit verification and documentation related to: (1) Shear testing, That: (i) Demonstrates that the BOP will shear the drill pipe and any electric-, wire-, slick-line to be used in the well;		As written, this would shut down many drilling operations for a long period as many rigs do not currently have shearing capability that would conform in regard to the electric-, wire-, slick-line requirement. Replace BOP with shear ram to confirm it doesn't need to be specific to a particular BOP assembly. Extend the requirement for Non-drill pipe to 5 years (e.g., wire-line)
§250.732(b)(1)ii	What are the BSEE-approved verification organization requirements for BOP systems and system components?	(ii) Demonstrates the use of test protocols and analysis that represent recognized engineering practices to ensure repeatability, reproducibility of the test, and that the testing was performed by a facility that meets generally accepted quality assurance standards;		This wording is vague and unclear. It would be very difficult to know when/if conformance was achieved.
§250.732(b)(1)iii	What are the BSEE-approved verification organization requirements for BOP systems and system components?	(iii) Provides a reasonable representation of field applications, taking into consideration the physical and mechanical properties of the drill pipe;		The actual shear testing should be in accordance with current industry standards only. This includes shearing the drill pipe with zero wellbore pressure and zero tension. There is a safety risk when shearing a drill pipe in the lab with high pressure in the wellbore and flowing conditions. Moreover, it is not practical (and there are no test facilities with this capability) to perform shear tests this way. The calculations consider the field application, taking into consideration the mechanical properties of the drill pipe and loading conditions. Effects of wellbore pressure on shear pressure should be calculated and be included in the test report.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.732(b)(1)iv	What are the BSEE-approved verification organization requirements for BOP systems and system components?	(iv) Ensures testing was performed on the outermost edges of the shearing blades of the positioning mechanism as required in § 250.734(a)(16);		Remove the section of "performed on the outmost edges" and is performed as required in 250.734(a)(16) Inconsistent with other section, § 250.734(a)(16)(i), that allows 7 years for pipe centering technology to be developed. Why must industry perform shear testing like this now when we have 7 years before the pipe centering requirement is in effect? If BSEE wants to ensure shear tests are performed on "off-centered" pipe, the "outermost edges" limitation for off-centered pipe should be defined by the OEM (i.e. the pipe should be off-centered to the maximum extent defined by the OEM's shear ram specification).
§250.732(b)(1)v	What are the BSEE-approved verification organization requirements for BOP systems and system components?	(v) Demonstrates the shearing capacity of the BOP equipment to the physical and mechanical properties of the drill pipe; and		Specify drill pipe for use in the well.
§250.732(b)(2)	What are the BSEE-approved verification organization requirements for BOP systems and system components?	You must submit verification and documentation related to: Pressure integrity testing and, That: (i) Shows that testing is conducted immediately after the shearing tests; (ii) Demonstrates that the equipment will seal at the rated working pressure of the BOP for 30 minutes; and (iii) Includes all test results.		Delete requirement for sealing pressure due to potential confusion offshore. Also, test pressure should be MASP/MAWHP, or the RWP of the sealing preventer above the uppermost shear ram, whichever is lower. Pressure test hold time should be consistent with relevant industry standards (e.g. 5 minutes having met acceptance criteria).
§250.732(b)(3)	What are the BSEE-approved verification organization requirements for BOP systems and system components?	You must submit verification and documentation related to: (3) Calculations, That: Include shearing and sealing pressures for all pipe to be used in the well including corrections for MASP.		Proposed text should consider that MASP load would be constrained by the rated working pressure of the sealing preventer located directly above the uppermost shear ram.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.732(c)	What are the BSEE-approved verification organization requirements for BOP systems and system components?	(c) For wells in an HPHT environment, as defined by § 250.807(b), you must submit verification by a BSEE-approved verification organization that the verification organization conducted a comprehensive review of the BOP system and related equipment you propose to use. You must provide the BSEE-approved verification organization access to any facility associated with the BOP system or related equipment during the review process. You must submit the verifications required by this paragraph to the appropriate District Manager and Regional Supervisor before you begin any operations in an HPHT environment with the proposed equipment.		Operators are unable to grant organizations "access to any facility" as the sites are controlled by OEMs and may be restricted. Furthermore, review of documentation provided by OEM personnel should be sufficient. "Access to facility" should be "access to documentation"
§250.732(c)(1)	What are the BSEE-approved verification organization requirements for BOP systems and system components?	You must submit: (1) Verification that the verification organization conducted a detailed review of the design package to ensure that all critical components and systems meet recognized engineering practices.		Critical components lack definition. API Standard 53 should be leveraged for identification of critical components.
§250.732(c)(2)	What are the BSEE-approved verification organization requirements for BOP systems and system components?	You must submit: (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. Including: (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.		Recommend that the testing process refer to the appropriate validation testing required in industry specifications (e.g., API 16 A / 16 C / 16 D)

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.732(c)(4)	What are the BSEE-approved verification organization requirements for BOP systems and system components?	You must submit: (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. Including: 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.		Recommend that the wording be modified as such: Including the quality control and assurance mechanisms comply to API Specification Q1
§250.732(d)	What are the BSEE-approved verification organization requirements for BOP systems and system components?	(d) Once every 12 months, you must submit a Mechanical Integrity Assessment Report for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility. This report must be completed by a BSEE-approved verification organization. You must submit this report to the Chief, Office of Regulatory Programs: Bureau of Safety and Environmental Enforcement: 45600 Woodland Road, Sterling, Virginia 20166. This report must include:		Recommend removing this section as all subparts are included in other existing or proposed CFR requirements, which are typically addressed on a frequency less than 12 months and often required with APD submissions. As written, this would require considerable additional costs and resources with no additional benefits or reduction of risk.
§250.733(a)	What are the requirements for a surface BOP stack?	(a) When you drill or conduct operations with a surface BOP stack, you must install the BOP system before drilling or conducting operations to deepen the well below the surface casing and after the well is deepened below the surface casing point. The surface BOP stack must include at least four remote-controlled, hydraulically operated BOPs, consisting of one annular BOP, one BOP equipped with blind-shear rams, and two BOPs equipped with pipe rams.	(a) When you drill or conduct operations with a surface BOP stack, you must install the BOP system before drilling or conducting operations to deepen the well below the surface casing and after the well is deepened below the surface casing point. A documented risk assessment shall be performed by the operator for all BOP arrangements to identify ram placements and configurations to be installed. The assessment shall include tapered strings, casings, completion equipment, test tools, etc.	

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.733(a)(2)	What are the requirements for a surface BOP stack?	(2) The two BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, excluding the bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools.	(2) The two BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing (excluding control lines, flat packs, etc.), excluding the bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools.	The proposed rule is a repeat of what was stated in 250.730 (a)(3). It was already established in section 250.730(a) that the BOP, including pipe and variable bore rams, be of RWP greater than MASP. MASP does not need to be repeated in every subsection. Closing a ram preventer on tubing and control lines, flat packs, etc. is not currently achievable, nor is it a realistic expectation for the near future. If it is BSEEs requirement that ram preventers be capable of sealing in this condition, this regulation would not be possible to meet and industry would be shut down in the Gulf of Mexico.
§250.733(b)	What are the requirements for a surface BOP stack?	(b) If you plan to use a surface BOP on a floating production facility you must:		
§250.733(b)(2)	What are the requirements for a surface BOP stack?	(2) Use a dual bore riser configuration, for risers installed after the effective date of this rule, before drilling or operating in any hole section or interval where hydrocarbons are, or may be, exposed to the well. The dual bore riser must meet the design requirements of API RP 2RD (as incorporated by reference in §250.198) including appropriate design for the most extreme anticipated operating and environmental conditions.	(2) Use a dual bore riser configuration, or approved alternative dual barrier system, for floating production facilities, installed after the effective date of this rule, before drilling or operating in any hole section or interval where hydrocarbons are, or may be, exposed to the well. Any dual bore risers installed after the publication of this rule must meet the design requirements of API RP 2RD (as incorporated by reference in §250.198) including appropriate design for the most extreme anticipated operating and environmental conditions. For operations using risers before the effective date of this rule, the continued use of single bore risers is allowed.	Many single bore risers are currently being used successfully. Existing operations using single bore risers should not be penalized and required to purchase new dual bore systems unless BSEE can fully justify the proposed rule.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.733(e)	What are the requirements for a surface BOP stack?	(e) You must install hydraulically operated locks.	Delete requirement for non-HPHT surface BOPS. Require the hydraulic locks for surface BOPs on HPHT wells only.	The majority of surface stacks currently operating have only manual locks. Converting manual lock bonnet doors to hydraulic lock bonnet doors would be an expensive and timely process. OEMs would not have the inventory on shelves to fulfill orders. Control systems may also have to be retrofitted to allow independent lock/unlock function of certain ram locks. A time frame of three months is not achievable for rigs that do not have hydraulically operated locks and the BOP controls system to operate them. While hydraulically operated locks remove the operator from the vicinity they do not provide the reliability of a manual lock. Subsea BOPs require hydraulically operated locks because they are under water, not because they are a mechanically superior to the manual lock. Manually operated locks on a surface stack are much simpler in mechanical design and predicted reliability. It is possible that some type of rotating end assembly could be designed and manufactured to replace a mechanical lock rods and handles, but three months is insufficient time to implement the equipment needed to meet the intent of the rule change.
§250.734(a)	What are the requirements for a subsea BOP system?	(a) When you drill or conduct operations with a subsea BOP system, you must install the BOP system before drilling to deepen the well below the surface casing or conducting operations if the well is already deepened beyond the surface casing point. The District Manager may require you to install a subsea BOP system before drilling or conducting operations below the conductor casing if proposed casing setting depths or local geology indicate the need. The following table outlines your requirements.	(a) When you drill or conduct operations with a subsea BOP system, you must install the BOP system before drilling to deepen the well below the surface casing or conducting operations if the well is already deepened beyond the surface casing point.	Unclear as to why the District Manager would request installation of a subsea BOP before the well reaches the defined surface casing point. Prematurely installing a subsea BOP and shutting in on a kick before installation of surface casing, would increase the risk broaching to the seafloor.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.734(a)(01)	What are the requirements for a subsea BOP system?	When operating with a subsea BOP system, you must: (1) Have at least five remote-controlled, hydraulically operated BOPs; Additional requirements You must have at least one annular BOP, two BOPs equipped with pipe rams, and two BOPs equipped with shear rams. For the two shear ram requirement, you must comply with this requirement within 5 years from the publication of the final rule. (i) Both BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, excluding the bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools. (ii) Both shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that includes heavy-weight pipe or collars), workstring, tubing, appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric-, wire-, slick-line in the hole under MASP. At least one shear ram must be capable of sealing the wellbore after shearing under MASP conditions as defined for the operation. Any non-sealing shear rams must be installed below the sealing shear rams.	When you drill or conduct operations with a subsea BOP stack, a documented risk assessment shall be performed by the operator for all BOP arrangements to identify ram placements and configurations to be installed. The assessment shall include tapered strings, casings, completion equipment, test tools, etc.	ExxonMobil has issue with the Class 5 BOP arrangement with two pipe rams and two shear rams for all moored rigs. We are in alignment with the wording in API Standard 53 which states one blind shear ram can be used on a moored rig if justified through a proper risk assessment. In the majority of well control events, there is pipe in the hole and well control responses are completed without using shear rams. In some cases, it would be more prudent to have 3 rams and 1 shear ram, minimum, in a class 5 stack. For example, a subsea test tree (SSTT) is often used to latch the tubing hanger of subsea wells, and the SSTT may require a large OD lower ram (outside the range of some variable bore rams); where the Class 5 arrangement with two shear rams and two pipe rams is used it may result in only one pipe ram being able to close on the string below the SSTT when it may be more appropriate to utilize a stack with 1 shear ram and three pipe rams. As a result of the proposed rule a number of rigs with four ram subsea BOP systems would be prevented from working in OCS waters and this impact should be considered in the RIA. Furthermore, some DP rigs have sealing shear rams above and below casing shear rams which would be prevented by the proposed rule ("Any non-sealing shear ram must be installed below at least one sealing shear ram"). It is requested that BSEE confirm that the 5-year implementation time applies beyond the "two shear ram requirement" to the whole section in order to allow for the introduction of technology to allow for the shearing of flat packs, slickline, etc.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.734(a)(03)	What are the requirements for a subsea BOP system?	When operating with a subsea BOP system, you must: (3) Have the accumulator capacity located subsea, to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface. Additional requirements The accumulator capacity must: (i) Function each required shear ram, choke and kill side outlet valves, one pipe ram, and disconnect the LMRP. (ii) Have the capability of delivering fluid to each ROV function i.e., flying leads. (iii) Have dedicated independent bottles for the autoshear, deadman, and EDS systems. (iv) Perform under MASP conditions as defined for the operation.	When operating with a subsea BOP system, you must: (3) Have the accumulator capacity located subsea, to provide closure of all assigned components to secure the well within the response times specified in API Standard 53 in case of a loss of the power fluid connection to the surface. Additional requirements: Within 5 years of the publication of the final rule, the accumulator capacity must be sufficient to: (i) Close each required shear ram. (ii) Have accumulator bottles that are dedicated to the emergency systems for both the autoshear and deadman.	The proposed rule implies that adequate useable accumulator fluid be stored subsea to fully function a "perceived" EDS sequence that closes both shear rams, a pipe ram, and unlatches the LMRP connector. Current guidance in API Standard 53 and API Specification 16D for EDS system design calls for a minimum volume to close one blind shear ram and unlatch the LMRP and allows surface bottles to contribute to the EDS sequence. In an actual EDS execution, the pipe/hangoff ram would be closed when the rig is in the yellow alert. For a well in 7500' of water using 15 gallon bottles and a rig with a current EDS of closing one shear ram and unlatching the LMRP, calculations indicate that 86 subsea bottles would be required. If it is assumed that existing rigs have up to 30 subsea bottles available presently (depends on the rig) then an additional 56-86 bottles would need to be installed. For autoshear and deadman systems, API Standard 53 and API Specification 16D allow a single, dedicated subsea bottle supply to be shared and used by either system. For the same well in 7500' of water using 15 gallon bottles, calculations indicate that to close both casing shear and blind shear ram, 68 subsea bottles would be required. Since the proposed rule stipulates that both autoshear and deadman systems must have their own independent supply, then an additional 68 bottles would be required. In these examples, 124 to 154 new 15-gallon bottles would be required subsea. Mounting this many bottles on the BOP frame would greatly hinder an ROV's ability to view the BOP components on routine inspections. To meet the proposed rule, it is possible that 4 x forty bottle Subsea Accumulator Modules (SAMs) would need to be deployed.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.734(a)(04)	What are the requirements for a subsea BOP system?	(4) Have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention capability; Additional requirements: The ROV must be capable of performing critical functions including opening and closing each shear ram, choke and kill side outlet valves, all pipe rams, and LMRP disconnect under MASP conditions as defined for the operation. The ROV panels on the BOP and LMRP must be compliant with API RP 17H (as incorporated by reference in § 250.198).	(4) Have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention capability as per the defined ROV intervention in S53 (Ref 7.4.16.1.1); Additional requirements: At a minimum, the ROV must be capable of closing one set of pipe rams, closing one set of blind shear rams, and unlatching the LMRP under MASP conditions as defined for the operation. The ROV panels on the BOP and LMRP must be compliant with API RP 17H (as incorporated by reference in § 250.198).	ExxonMobil's position is that drilling BOP ROV intervention be limited to closing the BOP to secure the well and unlatching the LMRP, if required. Numerous shuttle valve additions would be required increasing leak potential for questionable benefit. Numerous control panels and ROV manifold additions required on the BOP which would restrict maintenance access and ROV views of BOP. ROV ball valves required on functions to lock in control pressure and allow ROV freedom to move about doing other tasks. Could require disabling failsafe close pressure assist circuits or plumbing more complicated circuits to cycle valves open and closed without losing failsafe close assist fluid from dedicated failsafe accumulator bottles. May be difficult to determine if valve is fully open which could elevate risk of pumping fluid across a valve gate and creating a wash area across seal area. Availability of equipment to meet the proposed requirement within 3 months of publication is not possible.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.734(a)(06)	What are the requirements for a subsea BOP system?	(6) Provide autoshear, deadman, and EDS systems for dynamically positioned rigs; provide autoshear and deadman systems for moored rigs; Additional requirements: (i) Autoshear system means a safety system that is designed to automatically shut-in the wellbore in the event of a disconnect of the LMRP. This is considered a rapid discharge system. (ii) Deadman system means a safety system that is designed to automatically shut-in the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods. This is considered a rapid discharge system. (iii) Emergency Disconnect Sequence (EDS) system means a safety system that is designed to be manually activated to shut-in the wellbore and disconnect the LMRP in the event of an emergency situation. This is considered a rapid discharge system. (iv) Each emergency function must close at a minimum, two shear rams in sequence and be capable of performing their expected shearing and sealing action under MASP conditions as defined for the operation. (v) Your sequencing must allow a sufficient delay for closing the upper shear ram after beginning closure of the lower shear ram to provide for maximum shearing efficiency. (vi) The control system for the emergency functions must be a fail-safe design, and the logic must provide for the subsequent step to be independent from the previous step having to be completed.	(6) Provide autoshear, deadman, and EDS for moored and dynamically positioned rigs (unless the moored rig can operate without an EDS under the given parameters of API Standard 53); Additional requirements: (i) Autoshear system means a safety system that is designed to automatically shut-in the wellbore in the event of a disconnect of the LMRP. This is considered a rapid discharge system. (ii) Deadman system means a safety system that is designed to automatically shut-in the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods. This is considered a rapid discharge system. (iii) Emergency Disconnect Sequence (EDS) system means a safety system that is designed to be manually activated to shut-in the wellbore and disconnect the LMRP in the event of an emergency situation. This is considered a rapid discharge system. (iv) Control systems for autoshear, deadman, and EDS functions should be designed to allow selected closure of the shear rams based on the actual operating condition. (v) You must use a risk-based assessment (RBA) to evaluate the optimum shear ram activation sequence to ensure the safety of personnel, the reliability of the BOP equipment, and the well securement for different operational phases of the wellbore, including but not limited to, (1) drillpipe across BOP, (2) BHA across BOP, (3) casing across BOP, (4) cementing casing, (5) cementing in open hole, (6) wireline across BOP, (7) testing BOP's, and (8) well testing. These RBA's and your justification for the critical function sequences shall be included and approved with the APD package. (v) When emergency sequencing involves closing both the casing shear ram and the blind shear ram, your sequencing must allow a sufficient delay to allow the casing shear rams to fully function and to clear any tubular from the BOP body adjacent to the blind shear ram area before those sealing rams activate to close. (vi) The control system for the emergency functions must be a fail-safe design, and the logic must provide for the subsequent step to be independent from the previous step having to be completed.	Emergency function sequence of the BOPs should be operation specific and not a blanket order to close both casing shear and blind shear ram in all situations. For most drilling cases, it is not always necessary or desired to close the casing shear rams. Shear and seal tests and/or calculated shear capability would have confirmed that the blind shear rams are capable of shearing drillpipe and sealing the wellbore. Firing the casing shear rams unnecessarily could result in lowering the useable fluid in accumulator bottles which could lower operating pressure available for the blind shear ram closure. In most drilling EDS cases, the hangoff pipe rams would be closed on the drillpipe and the tooljoint slacked off and set on the closed hangoff ram during a "yellow alert" EDS condition. Thus, the annulus side of the wellbore is sealed by the hangoff ram and the drillstring could have one or more float valves in the BHA dependent on operator preference. If the EDS situation develops to "red alert", then the driller can fire the blind shear ram only to shear the pipe and seal the wellbore. This is the quickest way to seal the wellbore, cut with the highest bottle pressure, cut and seal with one cut, and stand by for LMRP release. The only time casing shears should be included in the emergency function is when hard to shear items like 13-5/8" casing and smaller are across the BOP. In this situation, an attempt should be made to cut the big tubular and pick it up clear of the blind shear rams before closing the sealing blind shear rams. With casing strings larger than 13-5/8" or other non-shearables, alternative procedures are required for emergency functions and it may be preferred not to function any shear ram but to disconnect the LMRP, then move a safe distance and pull tubulars out of BOP area prior to attempting an emergency closure. In most instances, this would involve top hole operations where hydrocarbon zones may not be exposed. This action should be carefully evaluated and risk-assessed.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.734(a)(07)	What are the requirements for a subsea BOP system?	When operating with a subsea BOP system, you must: (7) Demonstrate that any acoustic control system will function in the proposed environment and conditions; Additional requirements: If you choose to install an acoustic control system in addition to the autoshear, deadman, and EDS requirements, you must demonstrate to the District Manager, as part of the information submitted under § 250.731, that the acoustic system will function in the proposed environment and conditions. The District Manager may require additional information.		Industry is concerned of unintended consequences of this rule. Currently, a BOP acoustic control system is not required by BSEE to work in OCS waters. However, there are rigs working in OCS waters that have acoustic systems installed and industry feels that these systems could have good potential for secondary, emergency control of the BOP. The reliability of the systems, however, is not fully established. Industry feels the need to trial the systems to evaluate the full potential of the technology. However, industry does not want to be penalized by BSEE if the system fails to perform. As long as other secondary and emergency BOP control systems are available and working, it is unreasonable to have to pull a BOP if the acoustic system incurs a problem that does not impact the overall minimum system requirements. This proposed rule could have the unintended consequence of rig contractors simply removing acoustic systems to eliminate the potential of having to pull them to make repairs.
§250.734(a)(08)	What are the requirements for a subsea BOP system?	When operating with a subsea BOP system, you must: (8) Have operational or physical barrier(s) on BOP control panels to prevent accidental disconnect functions; Additional requirements: Incorporate enable buttons on control panels to ensure two-handed operation for all critical functions.	When operating with a subsea BOP system, you must: (8) Have operational or physical barrier(s) on BOP control panels to prevent accidental disconnect functions; Additional requirements: Incorporate two-handed operation for all critical functions.	API documents require two handed operation and not "Enable" button as proposed. Rule should be revised to be in line with industry standards.
§250.734(a)(12)	What are the requirements for a subsea BOP system?	When operating with a subsea BOP system, you must: (12) Before removing the marine riser, displace the fluid in the riser with seawater; Additional requirements: You must maintain sufficient hydrostatic pressure or take other suitable precautions to compensate for the reduction in pressure and to maintain a safe and controlled well condition. You must follow the requirements of § 250.720(b).	When operating with a subsea BOP system, you must: (12) Before planned removal of marine riser, excluding EDS, displace the fluid in the riser with seawater; Additional requirements: You must maintain sufficient hydrostatic pressure or take other suitable precautions to compensate for the reduction in pressure and to maintain a safe and controlled well condition. You must follow the requirements of § 250.720(b).	

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.734(a)(13)	What are the requirements for a subsea BOP system?	When operating with a subsea BOP system, you must: (13) Install the BOP stack in a well cellar when in an ice-scour area; Additional requirements: Your well cellar must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.		This proposed requirement is addressed in, and would conflict with, the proposed Arctic OCS rules currently under review. It should be removed from this proposal. Any requirement should be risk-based and fit-for-purpose. As written, the proposal does not give any consideration to likelihood of scour or ability to propose alternatives.
§250.734(a)(15)	What are the requirements for a subsea BOP system?	When operating with a subsea BOP system, you must: (15) Install a gas bleed line with two valves for annular preventer; Additional requirements: (i) The valves must hold pressure from both directions; (ii) If you have dual annulars, where one annular is on the LMRP and one annular is on the lower BOP stack, you must install a gas bleed line on each annular.	When operating with a subsea BOP system, you must: (15) Install a gas bleed line with two valves for the annular preventer as per guidance in API Standard 53, items 7.2.3.2.4 and Figures 11 and 13; (i) The valves must hold pressure from both directions; (ii) If you have dual annulars, where one annular is on the LMRP and one annular is on the lower BOP stack, consideration should be given to installing gas bleed valves and a line under each annular.	The upper annular is traditionally the working annular in a well control situation, thus the bleed valves are traditionally installed below the upper annular. Adding another set of gas bleed valves under the lower annular would require four pilot lines and two additional SPM valves per pod. Spare pilot lines and SPM's are limited and may be needed for additional pipe ram or shear ram functions which is a higher priority. New built DP rigs may have spare access but older moored rigs may have few spares. Request BSEE to clarify technical reason to add a set of gas bleed valves under the lower annular in this situation.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.734(a)(16)	What are the requirements for a subsea BOP system?	When operating with a subsea BOP system, you must: (16) Use a BOP system that has the following mechanisms and capabilities: Additional requirements: (i) A mechanism coupled with each shear ram to position the entire pipe, including connection, completely within the area of the shearing blade and ensure shearing will occur any time the shear rams are activated. This mechanism cannot be another ram BOP or annular preventer, but you may use those during a planned shear. You must install this mechanism within 7 years from the publication of the final rule; (ii) The ability to mitigate compression of the pipe stub between the shearing rams when both shear rams are closed; (iii) If your control pods contain a subsea electronic module with batteries, a mechanism for personnel on the rig to monitor the state of change of the subsea electronic module batteries in the BOP control pods.	When operating with a subsea BOP system, you must: (16) Within 7 years, use a BOP system that has proven ability to shear drill pipe tube when the pipe is positioned on the outermost edges of the shearing blades under side-loading conditions defined by the OEM; (i) The ability to accept the pipe stub between the shearing rams when both shear rams are closed.	Proposed rule 250.732 (b)(1)(iv) requires that cut tests be performed on the outermost edges of the shearing blades of the positioning mechanism as required in this rule. If current shear rams are capable of shearing pipe on the outermost edges of the cutting blade without aid from a centering device, the intent is met without having to redesign a shear ram. Need BSEE clarification if there proposed rule verbiage is a side-load shear test or pipe positioned on the outer edge of the shear blades? If side-load is desired, an unanswered question is how much side load force to apply and how much is realistic? The proposed BSEE statement in (iii) regarding SEM's and batteries is out of place for this equipment requirement and should be proposed in a more applicable section.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.734(b)	What are the requirements for a subsea BOP system?	(b) If operations are suspended to make repairs to any part of the subsea BOP system, you must stop operations at a safe downhole location. Before resuming operations you must: (1) Submit a revised permit with a verification report from a BSEE-approved verification organization documenting the repairs and that the BOP is fit for service; (2) Perform a new BOP test in accordance with §§ 250.737 and 250.738 upon relatch including deadman and ROV intervention; and (3) Receive approval from the District Manager.	If operations are suspended to make repairs to any part of the subsea BOP system, you must stop operations at a safe downhole location. Before resuming operations you must: (1) Submit a revised permit with a verification report from a verification organization documenting the repairs and that the BOP is fit for service; (2) Perform a new BOP test in accordance with §§ 250.737 and 250.738 upon relatch including any functions affected during the repair; and (3) Receive approval from the District Manager.	We feel it is absolutely not necessary to retest deadman and ROV intervention functions every time the BOP is latched. We concur with IADC that if any part of the deadman or ROV systems were dismantled, repaired, or affected as part of the BOP repair, then it would be prudent to verify functionality of these systems upon re-latching on the well. Because there is a low probability but very high consequence involved with each subsea deadman test that requires killing power and control fluid to the pods, we feel there is a definite safety risk to personnel, equipment, and well. It is our stance that the deadman control system (electronic and hydraulic) should be verified on surface before deployment but subsea tests should be limited to rigs that have safety systems built into the control circuits that allow deadman accumulator volume testing to be conducted without killing the control pods. Because of this very high concern for dead pods on a DP vessel, we suggest BSEE consider a 3-year grace period for rigs without safety systems for doing deadman tests, to upgrade systems to make this test a safer, less worrisome operation for rig contractors and operators.
§250.735	What associated systems and related equipment must all BOP systems include?	All BOP systems must include the following associated systems and related equipment:		

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.735(a)	What associated systems and related equipment must all BOP systems include?	(a) A surface accumulator system that provides 1.5 times the volume of fluid capacity necessary to close and hold closed all BOP components against MASP. The system must operate under MASP conditions as defined for the operation. You must be able to operate all BOP functions without assistance from a charging system, with the blind shear ram being the last in the sequence, and still have enough pressure to shear pipe and seal the well with a minimum pressure of 200 psi remaining on the bottles above the precharge pressure. If you supply the accumulator regulators by rig air and do not have a secondary source of pneumatic supply, you must equip the regulators with manual overrides or other devices to ensure capability of hydraulic operations if rig air is lost;		Industry SMEs including OEM, Operator, Contractor, 3rd parties and BSEE collaborated to produce API Standard 53 design and sizing requirements. The industry has reviewed and revised these calculations to reflect how gasses behave at these temperatures and pressures. The BSEE proposed requirement contradicts the requirements of API Standard 53, is not achievable, and is sufficiently ambiguous that industry SMEs cannot achieve a common understanding of the intent. It is not just the direct impact of the additional number of accumulator bottles, but the associated changes to pumping systems and storage tanks. The proposed BSEE rule to "close all BOP functions" and hold closed against MASP may penalize rigs that have more BOP equipment than the minimum BOP specified by BSEE in proposed rule 250.734 (1) which is one annular and four rams. For rigs with two annulars and six or seven rams, the impact would be considerable. So, for those rigs which have more redundancy in equipment but fail to meet this proposed BSEE surface volume rule, theoretically they could strip equipment off the bigger, more redundant stacks to meet minimum BSEE BOP equipment and surface accumulator requirements. The volume requirement should be in relation to the BSEE minimum BOP equipment requirements. API Standard 53 and API Specification 16D are the guidelines that rigs are designed and built by to work worldwide. Thus, if BSEE changes the accumulator requirements, it would impact the rigs working in OCS waters. For certain older rigs already operating in OCS waters, the new requirement could force them to exit the U.S. as upgrade may not be feasible due to space issues. Likewise, rigs operating overseas may be restricted from working in OCS waters because of not meeting a BSEE requirement that is above and beyond API Standard 53 and API Specification 16D guidelines. Request that BSEE justify the reason for this proposed rule.
§250.735(e)	What associated systems and related equipment must all BOP systems include?	(e) The kill line that may be installed below the bottom ram, but it must be installed beneath at least one pipe ram;	(e) The lowermost line connected to the BOP stack shall be identified as the kill line. For BOPs that have lines installed on each side of the outlet below the lowermost well control ram, either may designated as a choke or kill line.	

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.735(f)	What associated systems and related equipment must all BOP systems include?	(f) A fill-up line above the uppermost BOP;	(f) A fill-up line usually connected to the diverter housing, or bell nipple, above the BOPs to facilitate adding drilling fluid to the hole, at atmospheric pressure.	
§250.735(g)	What associated systems and related equipment must all BOP systems include?	(g) Hydraulically operated locking devices installed on the sealing ram-type BOPs; and	(g) All sealing ram-type preventers shall be equipped with locking devices. Surface stacks can be equipped with manual locks and subsea stacks should be equipped with hydraulic locks.	See comments for 250.733(e)

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.736(d)	What are the requirements for choke manifolds, kelly valves, inside BOPs, and drill string safety valves?	(d) You must use the following BOP equipment with a rated working pressure and temperature of at least as great as the working pressure and temperature of the ram BOP during all operations: (1) A kelly valve installed below the swivel (upper kelly valve); (2) A kelly valve installed at the bottom of the kelly (lower kelly valve). You must be able to strip the lower kelly valve through the BOP stack; (3) If you operate with a mud motor and use drill pipe instead of a kelly, one kelly valve installed above, and one strippable kelly valve installed below, the joint of pipe used in place of a kelly; (4) On a top-drive system equipped with a remote-controlled valve, a strippable kelly-type valve installed below the remote-controlled valve; (5) An inside BOP in the open position located on the rig floor. You must be able to install an inside BOP for each size connection in the pipe; (6) A drill string safety valve in the open position located on the rig floor. You must have a drill-string safety valve available for each size connection in the pipe; (7) When running casing, a safety valve in the open position available on the rig floor to fit the casing string being run in the hole; (8) All required manual and remote-controlled kelly valves, drill-string safety valves, and comparable-type valves (i.e., kelly-type valve in a top-drive system) that are essentially full opening; and (9) A wrench to fit each manual valve. Each wrench must be readily accessible to the drilling crew.	(4) On a top-drive system equipped with two ball valves, the upper valve is air or hydraulically operated and controlled at the driller's console and the lower valve is a standard ball valve (sometimes referred to as a safety valve) and is manually operated, usually by means of a large hexagonal wrench. If necessary, to prevent or stop flow up the drill pipe during tripping operations, a separate drill pipe valve should be used rather than either of the two top drive valves. However, flow up the pipe might prevent stabbing this valve. In that case, the top drive with its valves can be used, keeping in mind the following cautions: (a) once the top drive's manual valve is installed, closed, and the top drive disconnected, a crossover may be required to install an inside BOP on top of the manual valve; (b) most top drive valves can not be stripped into 7-5/8" or smaller casing; (c) once the top drive's manual valve is disconnected from the top drive, another valve and crossover may be required.	Issue is "rated working pressure and temperature of at least as great as the working pressure and temperature of the ram BOP during all operations" (d) Interpretation of this requirement leads one to believe that a kelly and associated kelly equipment is required. Kelly's are seldom used in OCS jurisdiction and has limited applications. (3) This is not a gap in any industry documents. This methodology is obsolete and has been addressed with MMS in the past. This practice was discontinued in the 80's after the proven use and operation of top drives. This requirement is not a best practice. (4) More specific than Standard 53 and Standard 53 should be referenced as this proposed language is not well presented.
§250.737	What are the BOP system testing requirements?	Your BOP system (this includes the choke manifold, kelly valves, inside BOP, and drill string safety valve) must meet the following testing requirements:		

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.737(a)(1-2)	What are the BOP system testing requirements?	(a) Pressure test frequency. You must pressure test your BOP system: (1) When installed; (2) Before 14 days have elapsed since your last BOP pressure test, or 30 days since your last blind-shear ram BOP pressure test. You must begin to test your BOP system before midnight on the 14th day (or 30th day for your blind-shear rams) following the conclusion of the previous test;	(a) Pressure test frequency. You must pressure test your BOP system: (1) When installed; (2) Before 21 days have elapsed since your last BOP pressure test, or 30 days since your last blind-shear ram BOP pressure test. You must begin to test your BOP system before midnight on the 21st day (or 30th day for your blind-shear rams) following the conclusion of the previous test;	Recommend aligning with API Standard 53 requirements
§250.737(a)(3)	What are the BOP system testing requirements?	(3) Before drilling out each string of casing or a liner. You may omit this pressure test requirement if you did not remove the BOP stack to run the casing string or liner, the required BOP test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test, and the time elapsed between tests has not exceeded 14 days (or 30 days for blind-shear rams). You must indicate in your APD which casing strings and liners meet these criteria;	(3) Before drilling out each string of casing or a liner. You may omit this pressure test requirement if you did not remove the BOP stack to run the casing string or liner, the required BOP test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test, and the time elapsed between tests has not exceeded 21 days (or 30 days for blind-shear rams). You must indicate in your APD which casing strings and liners meet these criteria;	
§250.737(d)(02)	What are the BOP system testing requirements?	You must...: (2) Use water to test a surface BOP system. Additional requirements... (i) You must submit test procedures with your APD or APM for District Manager approval. (ii) Contact the District Manager at least 72 hours prior to beginning the test to allow BSEE representative(s) to witness testing. If BSEE representative(s) are unable to witness testing, you must provide the test results to the appropriate District Manager within 72 hours after completion of the tests.	You must...: (2) Use water to test a surface BOP system upon initial installation on the wellhead. Subsequent testing may be done with the fluid in use. Additional requirements... (i) You must submit test procedures with your APD or APM for District Manager approval. (ii) Contact the District Manager at least 72 hours prior to beginning the test to allow BSEE representative(s) to witness testing. If BSEE representative(s) are unable to witness testing, you must provide the test results to the appropriate District Manager within 72 hours after completion of the tests.	Experience shows that use of water may not be an appropriate safe practice. Suggest alternative language to select test fluid appropriate for the well conditions as addressed in Standard 53. Due to the elevation difference between rig floor and wellbay on some surface BOP stack installations, displacing weighted fluid with seawater to do the BOP test would reduce hydrostatic pressure on the wellbore. Unless the surface BOP is directly below the rig floor, where elevation change has little impact, it would be safer to conduct the BOP test with the same fluid that is in the wellbore at the time of the test.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.737(d)(03)	What are the BOP system testing requirements?	You must...: (3) Stump test a subsea BOP system before installation. Additional requirements...(i) You must use water to conduct this test. You may use drilling fluids to conduct subsequent tests of a subsea BOP system. (ii) You must submit test procedures with your APD or APM for District Manager approval. (iii) Contact the District Manager at least 72 hours prior to beginning the stump test to allow BSEE representative(s) to witness testing. If BSEE representative(s) are unable to witness testing, you must provide the test results to the appropriate District Manager within 72 hours after completion of the tests. (iv) You must test and verify closure of all ROV intervention functions on your subsea BOP stack during the stump test. (iv) You must follow (b) and (c) of this section.		Item (iv) is a time concern if rule 250.734(a)(4) is adopted. Due to the high number of functions required by that rule, it would take considerable time and effort to function test and verify every one of them and is not aligned with API Standard 53. We are not in favor of expanding 250.734(a)(4) above and beyond the current BSEE rule but believe any ROV control system that has been installed and confirmed once at the start of a well should not have to have a repeat test done on every stack pull if the system has not been repaired, reworked, modified, etc.
§250.737(d)(04)	What are the BOP system testing requirements?	You must...: (4) Perform an initial subsea BOP test. Additional requirements... (i) You must perform the initial subsea BOP test on the seafloor within 30 days of the stump test. (ii) You must submit test procedures with your APD or APM for District Manager approval. (iii) You must pressure test well-control rams according to (b) and (c) of this section. (iv) You must notify the District Manager at least 72 hours prior to beginning the initial subsea test for the BOP system to allow BSEE representative(s) to witness testing. (v) You must test and verify closure of at least one set of rams during the initial subsea test through a ROV hot stab. You must pressure test the selected rams according to (b) and (c) of this section.		Conflicts with API Standard 53 which specifies blind shear ram or pipe rams to be functioned by ROV but not pressure tested and only conducted annually. Recommend adopting API Standard 53 practice.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.737(d)(05)	What are the BOP system testing requirements?	You must...: (5) Alternate tests between control stations and pods. Additional requirements...(i) For two complete BOP control stations: (A) Designate a primary and secondary station, and both stations must be function-tested weekly, (B) The control station used for the pressure test must be alternated between pressure tests, and (C) For a subsea BOP, the pods must be rotated between control stations during weekly function testing, and the pod used for pressure testing must be alternated between pressure tests. (ii) Any additional control stations must be function tested every 14 days.	All well control components (excluding hydraulic connectors and shear rams) of the BOP stack shall be function tested to verify the component's intended operations at least once every seven days or as operations allow. Pressure tests qualify as function tests. Casing shear rams and blind shear rams shall be tested at least once every 21 days. Prior to deployment, all control stations and both pods shall be function tested. The operability of individual control stations shall be confirmed. Subsequent function tests shall be performed from one BOP control station and one pod weekly. These tests shall rotate through both pods and all control panels where all BOP functions are included. All possible redundant control possibilities are not required every seven days. A function test schedule shall be developed for rotating control stations and pods on a weekly rotation.	
§250.737(d)(06)	What are the BOP system testing requirements?	You must...: (6) Pressure test variable bore-pipe ram BOPs against the largest and smallest sizes of pipe in use, excluding the bottom hole assembly that includes heavy-weight pipe or collars and bottom-hole tools.	You must...: (6) During stump testing, pressure test variable bore-pipe ram BOPs against the largest and smallest sizes of pipe in use, excluding drill collars and bottom-hole tools; during subsequent testing, pressure test variable bore-pipe ram BOPs against the smallest size drill pipe in use, excluding drill collars and bottom-hole tools.	
§250.737(d)(10)	What are the BOP system testing requirements?	You must...: (10) Function test blind-shear ram BOPs every 14 days.	You must...: (10) Function test blind-shear ram BOPs every 21 days.	As per guidance in API Standard 53
§250.737(d)(12)	What are the BOP system testing requirements?	You must...: (12) Test and verify closure capability of all ROV intervention functions on your subsea BOP. Additional requirements... (i) Each ROV must be fully compatible with the BOP stack ROV intervention panels. (ii) You must submit test procedures, including how you will test each ROV intervention function, with your APD or APM for District Manager approval. (iii) You must document all your test results and make them available to BSEE upon request.	You must...: (12) test and verify closure of the following ROV intervention functions: (1) shear ram close, (2) one pipe ram close, and (3) LMRP unlock/unlatch intervention functions on your subsea BOP stack during the stump test. Additional requirements... (i) Each ROV must be fully compatible with the BOP stack ROV intervention panels. (ii) You must submit test procedures, including how you will test each ROV intervention function, with your APD or APM for District Manager approval. (iii) You must document all your test results and make them available to BSEE upon request.	See comments for 250.737(d)(4). If 250.734(a)(4) is adopted, BOP's could have as many as 70 functions per the proposed BSEE rule.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.737(d)(13)	What are the BOP system testing requirements?	You must...: (13) Function test autoshear, deadman, and EDS systems separately on your subsea BOP stack during the stump test. The District Manager may require additional testing of the emergency systems. You must also test the deadman system and verify closure of the shearing rams during the initial test on the seafloor. Additional requirements... (i) You must submit test procedures with your APD or APM for District Manager approval..... (ii) The procedures must also include the actions and sequence of events that take place on the approved schematics of the BOP control system and describe specifically how the ROV will be utilized during this operation. (iii) When you conduct the initial deadman system test on the seafloor, you must ensure the well is secure and, if hydrocarbons have been present, appropriate barriers are in place to isolate hydrocarbons from the wellhead. You must also have an ROV on bottom during the test. (iv) The testing of the deadman system on the seafloor must indicate the discharge pressure of the subsea accumulator system throughout the test. (v) For the function test of the deadman system during the initial test on the seafloor, you must have the ability to quickly disconnect the LMRP should the rig experience a loss of station-keeping event. You must include your quick-disconnect procedures with your deadman test procedures. (vi) You must pressure test the blind-shear ram(s) according to (b) and (c) of this section. (vii) If a casing shear ram is installed, you must describe how you will verify closure of the ram. (viii) You must document all your test results and make them available to BSEE upon request.	You must... (13) Function test autoshear, deadman, and EDS systems separately on your subsea BOP stack during the stump test. The District Manager may require additional testing of the emergency systems. You must also test the deadman system and verify closure of the shearing rams during the initial test on the seafloor, if a risk-based assessment results in a low probability, low risk exposure to perform the deadman actuation test. Rigs not meeting the low probability, low risk exposure criteria have 3 years to upgrade control systems to make the subsea deadman test safer to execute.	Despite this being an existing rule, we wish to reopen this item for discussion. Per prior comments, ExxonMobil recommend the adoption of API Standard 53 which requires EDS testing at commissioning, on surface before deployment and at least once every 5 years subsea. To do the deadman test subsea, many dynamic positioned rigs are having to kill power and fluid to the pods. Performing this test creates a low probability, very high risk to most rigs working in OCS waters as it can take several minutes to re-establish power and fluid to the pods. If a vessel positioning issue ever develops with the pods dead, timely disconnect of the LMRP connector could be an issue which could lead to undesired results in equipment loss or well damage. Having an ROV subsea and plugged into the LMRP connector unlatch port is not recommended option for an emergency EDS actuation. If a drive off occurs, the ROV tether could be damaged during the drive off or the ROV could be pulled away from the well with the vessel. Some newer rigs have safety systems built into the BOP controls that enable a “simulated” power and fluid loss situation to the pods making them fire the deadman sequence(s), while still having power and fluid at the pods but isolated from the deadman controls. If API Standard 53 is not adopted, we suggest that BSEE consider a 3-year grace period for all rigs to make similar upgrades to existing control systems that would allow low probability, low risk deadman testing to be performed on all rigs. Testing the deadman circuit is a desired verification test but many operations are at risk doing them at present.
§250.738	What must I do in certain situations involving BOP equipment or systems?	The table in this section describes actions that you must take when certain situations occur with BOP systems.		

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.738(c)	What must I do in certain situations involving BOP equipment or systems?	If you encounter the following situation: (c) Need to postpone a BOP test due to well-control problems such as lost circulation, formation fluid influx, or stuck pipe; Then you must . . .Record the reason for postponing the test in the daily report and conduct the required BOP test on the first trip out of the hole.	If you encounter the following situation: (c) Need to postpone a BOP test due to well-control problems such as lost circulation, formation fluid influx, or stuck pipe; Then you must . . .Record the reason for postponing the test in the daily report and conduct the required BOP test as soon as it can safely be performed.	
§250.738(e)	What must I do in certain situations involving BOP equipment or systems?	If you encounter the following situation: (e) Plan to operate with a tapered string; Then you must . . . Install two or more sets of conventional or variable-bore pipe rams in the BOP stack to provide for the following: two sets of rams must be capable of sealing around the larger-size drill string and two sets of pipe rams must be capable of sealing around the smaller size pipe, excluding the bottom hole assembly that includes heavy weight pipe or collars and bottom-hole tools.	If you encounter the following situation: (e) Plan to operate with a tapered string; Then you must . . . Install two or more sets of conventional or variable-bore pipe rams in the BOP stack to provide for the following: two sets of rams must be capable of sealing around the larger-size drill string and one set of pipe rams must be capable of sealing around the smaller size pipe, excluding the bottom hole assembly that includes heavy weight pipe or collars and bottom-hole tools.	We feel that the rule as proposed is not a very good option with a 4-ram BOP dressed with two shear rams and two pipe rams. Two of the three major BOP manufacturers do not offer VBR's to satisfy most tapered string configurations. For instance if using a 3-1/2" x 5-7/8" tapered string, two OEM's offer VBR's in 3-1/2" x 5-1/2" size range and then another set (either 5-1/2" x 7-5/8" or 5" x 7") would be needed for the 5-7/8" string. Thus, there would be only one ram to close on each pipe size. If the rig contracted for the work had this combination of drillstring and associated surface equipment only, then the operator would have to rent drillpipe to fit the VBR situation. For three ram, one shear ram stacks, this was typically not an issue for tapered strings because two rams could be dressed for the larger pipe size (which is typically at the top of the string while drilling or running tubing) and one ram could be dressed for the smaller pipe size. For any part of the tapered string, the annular(s) and shear ram(s) would also be available as a secondary means of securing the well in the event pipe rams fail to function.
§250.738(f)	What must I do in certain situations involving BOP equipment or systems?	If you encounter the following situation: (f) Plan to install casing rams or casing shear rams in a surface BOP stack; Then you must... Test the ram bonnets before running casing to the rated working pressure or MASP plus 500 psi. The BOP must also provide for sealing the well after casing is sheared. If this installation was not included in your approved permit, and changes the BOP configuration approved in the APD or APM, you must notify and receive approval from the District Manager.	If you encounter the following situation: (f) Plan to install casing rams or casing shear rams in a surface BOP stack; Then you must... Test the ram bonnets before running casing to the rated working pressure or MASP plus 500 psi. 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.	

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.738(i)	What must I do in certain situations involving BOP equipment or systems?	If you encounter the following situation: (i) You activate any shear ram and pipe or casing is sheared; Then you must . . . Retrieve, physically inspect, and conduct a full pressure test of the BOP stack after the situation is fully controlled. You must submit to the District Manager a report from a BSEE-approved verification organization certifying that the BOP is fit to return to service.	If you encounter the following situation: (i) You activate any shear ram and pipe or casing is sheared; Then you must . . . 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 certifying that the BOP is fit to return to service.	
§250.738(l)	What must I do in certain situations involving BOP equipment or systems?	If you encounter the following situation: (l) If a test ram is to be used; Then you must . . .Conduct the initial BOP test after latching up using a test tool, and test the wellhead/BOP connection to the maximum pressure for the approved ram test for the well. All hydraulically operated BOP components must also be functioned during the well connection test.	If you encounter the following situation: (l) If a test ram is to be used; Then you must . . .Conduct the initial BOP test after latching up using a test tool, and test the wellhead/BOP connection to the maximum pressure for the approved ram test for the well. All hydraulically operated BOP components (i.e. - applicable ram preventers, annulars, BOP side outlet valves) must also be functioned and pressure tested during the initial BOP test on the wellhead.	Would like confirmation that hydraulically operated items like C&K line connectors, LMRP connector, wet-mate connectors, pod stabs, and other stabs are not part of the BSEE expectation for this proposed rule.
§250.738(m)	What must I do in certain situations involving BOP equipment or systems?	If you encounter the following situation: (m) Plan to utilize any other well-control equipment (e.g., but not limited to, subsea isolation device, subsea accumulator module, or gas handler) that is in addition to the equipment required in this subpart; Then you must . . .Contact the District Manager and request approval in your APD or APM. Your request must include a report from a BSEE-approved verification organization on the equipment's design and suitability for its intended use as well as any other information required by the District Manager. The District Manager may impose any conditions regarding the equipment's capabilities, operation, and testing.	If you encounter the following situation: (m) Plan to utilize any other well-control equipment (e.g., but not limited to, subsea isolation device, subsea accumulator module, or gas handler) that is in addition to the equipment required in this subpart; Then you must . . .Contact the District Manager and request approval in your APD or APM. Your request must include a report 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.	

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.738(o)	What must I do in certain situations involving BOP equipment or systems?	If you encounter the following situation: (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); Then you must . . .Comply with all testing, maintenance, and inspection requirements in this subpart that are applicable to those well-control components. If any redundant component fails a test, you must submit a report from a BSEE-approved verification organization that describes the failure, and confirms that there is no impact on the BOP that will make it unfit for well-control purposes. You must submit this report to the District Manager and receive approval before resuming operations. The District Manager may require additional information.	If you encounter the following situation: (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); Then you must . . .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 that describes the failure, and confirms that there is no impact on the BOP that will make it unfit for well-control purposes. You must submit this report to the District Manager and receive approval before resuming operations. The District Manager may require additional information.	

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.738(p)	What must I do in certain situations involving BOP equipment or systems?	If you encounter the following situation: (p) Need to position the bottom hole assembly, including heavy-weight pipe or collars, and bottom-hole tools across the BOP for tripping or any other operations. Then you must . . .Ensure that the well has been stable for a minimum of 30 minutes prior to positioning the bottom hole assembly across the BOP. You must have, as part of your well-control plan required by § 250.710, procedures that enable the immediate removal of the bottom hole assembly from across the BOP in the event of a well-control or emergency situation (for dynamically positioned rigs, your plan must also include steps for when the EDS must be activated) before MASP conditions are reached as defined for the operation.	If you encounter the following situation: Need to position the bottom hole assembly, including heavy-weight pipe, drill collars, or other non-shearable items into the BOP while tripping or any other operations. Then you must ... Prior to positioning the bottom hole assembly into the BOP, perform a minimum 5-minute flow check on the trip tank to confirm that the well is not flowing. After a no-flow period has been confirmed, the bottom hole assembly may be tripped through the BOP. You must have, as part of your well-control plan required by § 250.710, procedures that outline emergency action plans to follow when handling non-shearables in the BOP during tripping operations and provide guidance for the timely removal of the bottom hole assembly from the BOP in the event of a well-control or emergency situation. For dynamically positioned rigs, your plan must also include steps for clearing non-shearables from the BOP for EDS activation.	The Well Control Plan should address site-specific operations, well specific operating guidelines, and communications protocol for tripping non-shearable items through the BOP. While tripping, pipe displacement is being monitored on the trip tank and the rig crew would already know that the well is taking the correct amount of mud while tripping and is in a safe overbalanced condition. The minimum 5-minute flow check is simply a precautionary step recommended to confirm that the well is not flowing with the drillstring static or not moving. We feel that a static flow check period of 30 minutes is not justified. Timely removal of the non-shearable from the BOP can encompass various operations including: (1) clearing the non-shearable from the subsea BOP by tripping in to get drillpipe into the BOP for closure or tripping out to close the blind shear rams (whichever, is most timely), (2) for a surface BOP, making up a drillpipe kick stand or single to the non-shearable items and lowering the string so that the BOP can be closed on the kick stand, and (3) dropping the drillstring and the non-shearable items while giving them time to fall and clear the BOP area for closure. The BSEE reference to "immediate removal of the BHA from the BOP" should be stricken as it is interpreted as an operation that requires only an instant to complete. "Timely" is a more appropriate word.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.739(a)	What are the BOP maintenance and inspection requirements?	(a) You must maintain and inspect your BOP system to ensure that the equipment functions as designed. The BOP maintenance and inspections must meet or exceed any OEM recommendations, recognized engineering practices, and industry standards incorporated by reference into the regulations of this subpart, including API Standard 53 (incorporated by reference in § 250.198). You must document how you met or exceeded the provisions of API Standard 53, maintain complete records to ensure the traceability of all critical components beginning at fabrication, and record the results of your BOP inspections and maintenance actions. You must make all records available to BSEE upon request.	(a)You must maintain and inspect your BOP system, as defined in API Standard 53 (incorporated by reference in § 250.198), to ensure that the equipment functions as designed. All BOP maintenance and inspections must meet the equipment owner's PM program. The equipment owner must document how they met or exceeded the provisions of API Standard 53, maintain complete records to ensure the required traceability of the equipment and record the results of your inspections and maintenance actions. All records must be made available to BSEE upon request.	Need to clarify the term "critical components". The statement 'Engineering practices and industry standards' is too vague and open to inconsistent interpretation.
§250.739(b)	What are the BOP maintenance and inspection requirements?	(b) A complete breakdown and detailed physical inspection of the BOP and every associated system and component must be performed every 5 years. This complete breakdown and inspection may not be performed in phased intervals. A BSEE-approved verification organization is required to be present during the inspection and must compile a detailed report documenting the inspection, including descriptions of any problems and how they were corrected. You must make this report available to BSEE upon request.	(b) At least every 5 years, the well control system components shall be inspected for repair or remanufacturing, in accordance with equipment owner's PM program and the manufacturer's guidelines. Individual components (e.g. ram bonnets, valve actuators) can be inspected on s staggered schedule. (As per API Standard 53, sections 7.6.9.3.1 and 6.5.7.3.1.	The proposed requirement is not consistent with API Standard 53 and has not been explicitly justified. The prohibition of phased inspections would put rigs out of service for several months and has not been addressed in the RIA. A complete disassembly of a BOP stack introduces additional safety risks as well as infant mortality of equipment into system. A requirement to follow this would negate Industry's current equipment integrity strategies. The requirement would create more heavy lifts in congested areas than are currently required and introduce additional safety risks. Technology and process exist and are in use today that allows for detailed inspection without disassembly. ExxonMobil believes that a third party presence is not always required due to the proposed competency requirements that require the subsea teams to be qualified to meet OEM standards and that review of recertification documentation should be sufficient.
§250.739(d)	What are the BOP maintenance and inspection requirements?	(d) You must ensure that all personnel maintaining, inspecting, or repairing BOPs, or critical components of the BOP system, meet the qualification and training criteria specified by the OEMs and recognized engineering practices.		OEMs do not provide training requirements to the Equipment Owners. The Equipment Owner's personnel training and competency requirements are addressed by SEMS. Recognized engineering practices are addressed by the applicable API standards and specifications.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.739(e)	What are the BOP maintenance and inspection requirements?	(e) You must make all records available to BSEE upon request. You must ensure that the rig owner maintains your BOP maintenance, inspection, and repair records on the rig for 2 years from the date the records are created or for a longer period if directed by BSEE. You must maintain all design, maintenance, inspection, and repair records at an onshore location for the service life of the equipment.	(e) You must make all records available to BSEE upon request. You must ensure that the equipment owner maintains the BOP maintenance, inspection, and repair records on the rig for 2 years from the date the records are created or for a longer period if directed by BSEE. The equipment owner must maintain all maintenance, inspection, and repair records at an onshore location for the service life of the equipment.	The equipment design data is proprietary to the OEM and therefore the design documentation cannot be maintained by anybody other than the product design owner (OEM). Equipment owners, and not operators, are responsible for the storage of maintenance, inspection and repair records.
§250.740(a)	What records must I keep?	You must keep a daily report consisting of complete, legible, and accurate records for each well. You must keep records onsite while well operations continue. After completion of operations, you must keep all operation and other well records for the time periods shown in § 250.741 at a location of your choice, except as required in § 250.746. The records must contain complete information on all of the following: (a) Well operations, all testing conducted, and any real-time monitoring data;	You must keep a daily report consisting of complete, legible, and accurate records for each well. You must keep records onsite while well operations continue. After completion of operations, you must keep all operation and other well records for the time periods shown in § 250.741 at a location of your choice, except as required in § 250.746. The records must contain complete information on all of the following: (a) Well operations, all testing conducted, and real-time monitoring data, per your Monitoring Plan;	
§250.740(f)	What records must I keep?	(f) Any significant malfunction or problem; and		The requirement regarding "any significant malfunction or problem" is ambiguous. Recommend BSEE provide some examples of what type malfunction or problem it suggests the Industry keeps records of (given that there is already a requirement for equipment failure reporting and that well control events and other drilling related problems are documented in the daily reports). This requirement might also be considered covered by 250.740(g)
§250.740(g)	What records must I keep?	(g) All other information required by the District Manager.	(g) All other information required by the District Manager in the interests of resource evaluation, waste prevention, conservation of natural resources, and the protection of correlative rights, safety, and environment.	Requirement is ambiguous. Additional information required.

Regulation Reference	Section title	Proposed Regulation Text	Recommended Text	Comments
§250.746(e)	What are the recordkeeping requirements for casing, liner, and BOP tests, and inspections of BOP systems and marine risers?	(e) Identify on the daily report any problems or irregularities observed during BOP system testing and record actions taken to remedy the problems or irregularities. Any leaks associated with the BOP or control system during testing are considered problems or irregularities and must be reported immediately to the District Manager, and documented in the WAR. If any problems or irregularities are observed during testing, operations must be suspended until the District Manager determines that you may continue; and	Identify on the daily report any problems or irregularities observed during BOP system testing and record actions taken to remedy the problems or irregularities. (i) Any minor leaks associated with the BOP control system during operations on the well that cannot be resolved are considered problems or irregularities and must be reported within 24 hours to the District Manager, and documented in the WAR. (ii) Leaks associated with BOP equipment testing during operations on the well that cannot be resolved are also considered problems or irregularities and must be reported within 12 hours to the District Manager. (iii) When problems or irregularities are observed, a risk-based assessment must be used to justify whether operations may continue safely or whether repair is required before resuming operations. Any problems, irregularities, and risk-based assessments must be submitted to and approved by the District Manager within the specified time period above; and	BSEE has specified in proposed rule 250.734 (a)(1) the minimum BOP equipment requirements (1 annular, 2 shear rams, 2 pipe rams). If a rig is in use with 2 annulars, 2 shear rams, and 4 pipe rams would industry be forced to secure a well and repair a redundant piece of BOP equipment fails a midnight pressure test. Would the District Manager be available at midnight to discuss and approve a 0.5-gallon per hour control system leak from an SPM on the open side of a redundant pipe ram that can be stopped by placing the ram in block position? Is it necessary to shut down operations for in a situation where the BOP system capability exceeds BSEEs minimum requirements? The proposed text could be better defined to provide some responsibility to the operator and rig contractor to make a risk based decision and notify BSEE within a certain time frame of noting the problem or irregularity.
§250.1703(b)	What are the general requirements for decommissioning	(b) Permanently plug all wells. All packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198);	(b) Permanently plug all wells. After the implementation date of this regulation, all permanently installed (as defined in the APD and/or APM) packers and bridge plugs installed during decommissioning must comply with API Spec. 11D1 (as incorporated by reference in § 250.198);	