AMERICAN PETROLEUM INSTITUTE

OFFSHORE OPERATORS COMMITTEE

IADC

NOIA America's Offshore Energy Industry

IPAA INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

PESA PETROLEUM EQUIPMENT & SERVICES ASSOCIATION

US Oil & Gas Association

August 6, 2018

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

Re: *Blowout Preventer Systems and Well Control Revisions, 1014–AA39*

Via electronic submission to: http://www.regulations.gov/

To whom it may concern:

The American Petroleum Institute (API), the International Association of Drilling Contractors (IADC), the Independent Petroleum Association of America (IPAA), the National Ocean Industries Association (NOIA), the Offshore Operators Committee (OOC), the Petroleum Equipment & Services Association (PESA), and the US Oil and Gas Association respectfully submit the following comments on the proposed regulatory revisions to Blowout Preventer Systems and Well Control requirements in 30 C.F.R. part 250. The Bureau of Safety and Environmental Enforcement (BSEE) published these proposed changes on May 11, 2018, in a notice of proposed rulemaking entitled, ''Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control Revisions.''

Safety is a core value for the oil and natural gas industry. We are committed to safe operations and support effective regulations in the area of blowout preventer systems and well control. We appreciate the actions of this Administration to eliminate unnecessary burden and to restore certainty and predictability to the offshore permitting and regulatory regimes. In particular, we welcome the Administration's commitment to review the final Well Control Rule because some of its provisions actually made operating offshore less safe and therefore, a review of this final rule is warranted. These trade associations represent oil and natural gas producers who conduct the vast majority of the Outer Continental Shelf (OCS) oil and natural gas exploration and production activities in the United States as well as the companies supporting the drilling, equipment manufacturing, construction, and support services for the offshore oil and natural gas industry. Our collective commitment to safe operations motivates us to ensure that the regulations in place foster safe operations today and into the future.

While we are pleased to see the Administration and the Department of the Interior (DOI) continuing to make strides to put in place a lasting, domestically-focused energy policy that will help the U.S. "maintain the Nation's position as a global energy leader," the proposed rulemaking leaves additional opportunity on the table. For too long the U.S. has been hampered by the lack of a strong domestic oil and natural gas energy policy. The oil and natural gas industry is committed to developing and producing domestic energy resources for the benefit of all Americans and doing so in a safe and environmentally sound manner. The below context and the attached detailed response demonstrates areas for continued improvement to the safety and economic competitiveness of the OCS oil and natural gas industry.

Secretarial Order 3350, America-First Offshore Energy Strategy, which implements Executive Order 13795, is an important step forward that will help the offshore oil and natural gas industry regain the cost-effective regulatory framework that promotes the certainty and predictability necessary to make the massive capital investments required to bring the benefits from offshore energy projects to the U.S. economy. This will serve to further the Department's stated goal "to ensure that responsible OCS exploration and development is promoted and not unnecessarily delayed or inhibited."

Our comments are submitted without prejudice to any of our member companies' right to have or express different or opposing views. We have encouraged all of our members to submit comments on the proposal.

This letter highlights below some aspects of the proposed rule that would not advance safety and yet would have the greatest negative impact on the industry. In addition, BSEE has solicited, and we have provided, input on specific aspects of the proposed revisions; we also offer additional detailed revisions to the original rule in Attachment A.

Drilling Margins

The 2016 Well Control Rule set a prescriptive drilling margin requirement of 0.5 ppg. Since that time, BSEE has recognized that it has approved operators' use of drilling margins that are less than the 0.5 ppg margin in instances where the prescriptive margin was not fit for purpose. In this proposal, BSEE specifically requests comment on whether this requirement should be eliminated or revised to alternative standards such as a performance-based, well type, or water depth model.

The current 0.5 ppg margin is arbitrary and does not ensure safety. The industry believes that replacing the current requirement with a performance-based standard under which an approved safe drilling margin would be established on a case-by-case basis, based on data and analysis specific to a particular well, is a safe and better alternative. Such an alternative would provide a risk-based approach that ensures safety and provides investment certainty to the industry. Attachment A provides alternative language for drilling margin requirements and attendant supporting rationale for BSEE's consideration.

BSEE also requests comment on whether there are situations where, despite not being able to maintain the approved safe drilling margin, an operator's continued drilling with an alternative margin creates little risk. In instances where an operator encounters a lost circulation zone, that operator would need to remedy the situation to move forward. Particularly when the lost circulation zone is on bottom, drilling ahead to get through the lost circulation zone may be the safest option to restore the integrity of the well rather than suspending drilling operations altogether to remedy the situation. It is appropriate for operators to specify how they will remedy an anticipated loss of circulation on bottom in the well's DWOP or APD. If an operator experiences an unanticipated loss of circulation or a reduced drilling margin, the operator should provide notice and the operator's plan for remedying the issue to BSEE within a reasonable timeframe.

API Standard 53

The incorporation of API Standard 53 4th edition should also include Addendum 1 to Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition (July 2016). Industry is finalizing the 5th edition and once it is published, consideration for incorporation by reference should be taken to ensure the U.S. OCS is operating to the latest API standard for well control systems, allowing for continued safety improvements into the future, and is consistent with the remainder of operations around the world.

BOP Equipment & Testing

Industry requests that BSEE align the proposed changes to the Well Control Rule with the 21-day testing interval outlined in API Standard 53 4th Edition (July 2016). This 21-day period has proven to provide assurance of a safe and reliable system without causing premature wear on the equipment. The existing 14-day regulation requirement results in an additional 53% of testing over a 12-month period with a corresponding increase in wear of seals and packers. Industry believes that the testing frequency of API Standard 53 4th Edition (July 2016) is the optimum requirement for worldwide operations. The 21-day testing period of API Standard 53 (July 2016) aligns with the global practice and capabilities of the existing technology installed and utilized in the GOM. If BSEE does not accept industry's proposal regarding a 21-day BOP testing interval, then we recommend BSEE engage in a pilot 21-day testing program to gather the data needed for assessing the difference in BOPE performance between 14 and 21-day testing intervals.

Industry and BSEE recognize that there are technologies that exist, or are in development, that can provide the operator, owner, and OEM with data regarding the equipment's performance. The combination of existing technologies, API Standard 53 failure reporting, and the potential use of emerging technologies may lead to product and process advances that further improve safety and reliability. As these technologies become more widely proven, Industry will continue to review the test frequency requirement within future revisions of API Standard 53.

Real Time Monitoring (RTM)
Industry recommends that RTM be applied to operations using subsea BOPs and surface BOPs from a floating rig defined by API Standard 53, which is already incorporated by reference into the regulations. This would clarify the intent of the RTM system and provide a clear and complete framework for RTM requirements.

With respect to specific operations under RTM (workover, completions, etc.), the covered operations will be defined by each individual Operator's RTM plan, which takes into account the risk of the operation, the individual Operator's Safety and Environmental Management System framework, and alignment through the permitting activity for the specific operation. These types of operations are generally lower risk due to lower complexity, known bottom hole conditions, and in the case of decommissioning, non-flowing wells.

Containment
Industry supports the proposed changes to 30 CFR 250.462, which would clarify the source control equipment requirements based on the operator's Regional Containment Demonstration (RCD) or Well Containment Plan (WCP). Similar to spill equipment (e.g. skimmers, sorbent boom, etc.), the majority of source control equipment has no other commercial purpose and is used solely for emergency containment operations, such as capping stacks, top hats and subsea dispersant wands. This unique containment equipment is maintained by specialty companies, is readily available for inspection at any time, and is maintained and stored for immediate use if an event occurs. Other equipment listed for source control that has broad commercial purpose, such as Remotely Operated Vehicles and vessels are readily available and frequently inspected and maintained for safe and efficient normal operations.

Economic Analysis
API contracted Calash and Blade Energy Partners to perform an independent economic impact analysis of the proposed revisions "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control Revisions." The report supports BSEE's assertion that the proposed rule increases the competitiveness of America's offshore energy industry. Consistent with the Executive and Secretarial Orders, undue burden has been removed. The report further demonstrates that, without further revision as proposed in Attachment A, an increase in inappropriately restrictive enforcement of the rules still poses a significant financial threat to the industry without a measurable safety benefit. Specifically, the prescriptive drilling margin could be used to limit ~~restrict~~ future offshore development.

We look forward to continued engagement with BSEE on these important regulatory requirements to assure that the energy that is fundamental to our society and its economic prosperity can be developed and delivered safely. It is important that safety regulations indeed enhance safety, rather than hinder it.

Thank you for your consideration of these comments, please do not hesitate to contact us if you have any questions.

Sincerely,

Holly Hopkins, API

Jason McFarland, IADC

Daniel Naatz, IPAA

Randall Luthi, NOIA

Evan Zimmerman, OOC

Leslie Beyer, PESA

Alby Modiano, US Oil and Gas Association

Attachment

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.198(h)(63)	(63) API Standard 53, Blowout Prevention Equipment and Systems for Drilling Wells, Fourth Edition, November,2012, incorporated by reference at §§ 250.730m 250.735, 250.737 and 240.739.	In order to remain current with the standards developed and adopted by industry, industry recommends that the regulations incorporate API Standard 53 4th Edition with its Addendum 1, issued in July 2016. Industry is finalizing the 5th edition of API 53, once it is published, consideration for incorporation by reference should be taken to ensure the U.S. OCS is operating to the latest API standard for well control systems and is consistent with the remainder of operations around the world.	Revise 250.198(h)(63) to read: API Standard 53, Blowout Prevention Equipment and Systems for Drilling Wells, Fourth Edition, November,2012, with Addendum 1, July 2016, incorporated by reference at §§ 250.730m 250.735, 250.737 and 240.739.
§250.198(h)(78)	(78) API Standard 65—Part 2, Isolating Potential Flow Zones During Well Construction; Second Edition, December 2010; incorporated by reference at §§ 250.415(f) and 250.420(a)(6);	Industry supports the proposed change which will clarify that the centralization requirements will be governed by API Standard 65-2, reducing the possibility of inconsistent	None. The proposed change is supported.

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		application across BSEE.	
§250.198 (h)(94)	(94) API Recommended Practice 17H, Remotely Operated Tool and Interfaces on Subsea Production Systems, Second Edition, June 2013, Errata January 2014, incorporated by reference at § 250.734(a)(4);	Industry supports the incorporation by reference of the updated edition of this standard for the reasons given in the preamble of the proposed rule.	None. The proposed change is supported.
§250.413(g)	(g) A single plot containing curves for estimated pore pressures, formation fracture gradients, proposed drilling fluid weights (surface and downhole), planned safe drilling margin, and casing setting depths in true vertical measurements;	In accordance with long standing practices between BSEE and Industry, Industry has reviewed and concurs with providing additional details as requested by BSEE. This continues to follow industry practice of providing additional data at the request of BSEE.	None. The proposed change is supported.
§250.414(c)	(c) Planned safe drilling margin that is between the estimated pore pressure and the lesser of estimated fracture gradients or casing shoe pressure integrity test and that is based on a risk assessment consistent with expected well conditions and operations. (1) Your safe drilling margin must also include use of equivalent downhole mud weight that is: (i) greater than the estimated pore pressure, and (ii) except as provided in paragraph (c) (2) of this section, a minimum of 0.5 pound per gallon below the lower of the casing	The 0.5 ppg value is arbitrary and does not ensure safety. Maintaining the equivalent downhole mud weight above pore pressure manages the potential for influx while managing equivalent circulating density below fracture	(c) Your drilling prognosis is part of your Conceptual Deepwater Operations Plan or APD and must include a planned safe drilling margin that is between the estimated pore pressure and the lesser of estimated fracture gradient or the casing shoe pressure integrity

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	shoe pressure integrity test or the lowest estimated fracture gradient. (2) In lieu of meeting the criteria in paragraph (c)(1)(ii) of this section, you may use an equivalent downhole mud weight as specified in your APD, provided that you submit adequate documentation (such as risk modeling data, off-set well data, analog data, seismic data) to justify the alternative equivalent downhole mud weight. (3) When determining the pore pressure and lowest estimated fracture gradient for a specific interval, you must consider related off-set and analogous well behavior observations, if available.	gradient (or casing shoe pressure integrity test) manages lost circulation. The regulation should focus on establishing downhole mud weight within this operational window. Further, retaining the arbitrary 0.5 ppg margin hinders promotion of enhanced technology (for example, low ECD drilling fluids, Managed Pressure Drilling), and engineering in well design. By prohibiting this evolution, the regulation could preclude future wells from being drilled safer. The implementation of these technologies will be necessary to enable development of future offshore resources. Industry would like to propose an engineered, performance-based approach standard and suggest replacing current	test and based on a risk assessment consistent with expected well conditions and operations. (1) Your safe drilling margin must provide for: (i) equivalent downhole mud weight that is greater than the estimated pore pressure, and (ii) equivalent circulating density (ECD) that is actively managed below the lesser of the lowest estimated fracture gradient or the casing shoe pressure integrity test. The ECD is supported with hydraulic modeling or other documentation (such as risk modeling data, related analog well data, seismic data). (2) When determining the pore pressure and lowest estimated fracture gradient for a specific interval, you must consider related off-set and analogous well behavior observations, if available.

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		text to the rule with recommended industry text. In the view of industry, the proposed text was developed to address the concerns and issues that BSEE raised within the preamble text. It is believed that the comments in this letter demonstrate the improved safety and clarity, to industry and the regulator, due to this proposed change. In an effort to build confidence for field development, industry proposes that BSEE apply this proposed text and include CDWOP and APD into the text, in an effort to provide opportunity for early alignment with BSEE for major capital investments going forward. Industry believes that the proposed text changes	

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		supports current practices and District Manager approval requirement is retained for all cases.	
§250.420(a)(6)	(6) Provide adequate centralization consistent with the guidelines of API Standard 65 –Part 2 (as incorporated by reference in § 250.198); and	Industry supports the proposed change which will clarify that the centralization requirements will be governed by API Standard 65-2, reducing the possibility of inconsistent application across BSEE.	None. The proposed change is supported.

<table>
<tr><th>Proposed Regulation Reference</th><th>Proposed New Regulation Text</th><th>Comments</th><th>Recommended Industry Text</th></tr>
<tr><td>§§250.421(c), (d), (e) and (f)</td><td>What are the casing and cementing requirements by type of casing string?
* * * * *
<table>
<tr><th>Casing type</th><th>Casing requirements</th><th>Cementing requirements</th></tr>
<tr><td>* * * * * * *</td><td></td><td></td></tr>
<tr><td>(c) Surface</td><td>Design casing and select setting depths based on relevant engineering and geologic factors. These factors include the presence or absence of hydrocarbons, potential hazards, and water depths</td><td>Use enough cement to fill the calculated annular space to at least 200 feet measured depth (MD) inside the conductor casing.
When geologic conditions such as near-surface fractures and faulting exist, you must use enough cement to fill the calculated annular space to the mudline.</td></tr>
<tr><td>(d) Intermediate</td><td>Design casing and select setting depth based on anticipated or encountered geologic characteristics or wellbore conditions</td><td>Use enough cement to cover and isolate all hydrocarbon-bearing zones and isolate abnormal pressure intervals from normal pressure intervals in the well.
As a minimum, you must cement the annular space 500 feet MD above the casing shoe and 500 feet MD above each zone to be isolated.</td></tr>
<tr><td>(e) Production</td><td>Design casing and select setting depth based on anticipated or encountered geologic characteristics or wellbore conditions</td><td>Use enough cement to cover or isolate all hydrocarbon-bearing zones above the shoe.
As a minimum, you must cement the annular space at least 500 feet MD above the casing shoe and 500 feet MD above the uppermost hydrocarbon-bearing zone.</td></tr>
<tr><td>(f) Liners</td><td>If you use a liner as surface casing, you must set the top of the liner at least 200 feet MD above the previous casing/liner shoe.
If you use a liner as an intermediate string below a surface string or production casing below an intermediate string, you must set the top of the liner at least 100 feet MD above the previous casing shoe.
You may not use a liner as conductor casing.
A subsea well casing string whose top is above the mudline and that has been cemented back to the mudline will not be considered a liner.</td><td>Same as cementing requirements for specific casing types. For example, a liner used as intermediate casing must be cemented according to the cementing requirements for intermediate casing.</td></tr>
</table></td><td>Industry agrees with proposed changes to paragraphs (c), (d), (e), and (f) for the reasons described in the preamble.</td><td>None. The proposed change is supported.</td></tr>
<tr><td>§250.423(a)</td><td>(a) You must ensure that the latching mechanisms or lock down mechanisms are engaged upon successfully installing the casing string. If there is an indication of an inadequate cement job, you must comply with §250.428(c).</td><td>Industry agrees with proposed change but believe that the second sentence "If there is any</td><td>(a) You must ensure that the latching mechanisms or lock down mechanisms are engaged upon successfully</td></tr>
</table>

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
		indication of an inadequate cement job, you must comply with § 250.428(c)." should be removed. There is no longer a reference to cementing outside of this sentence. The proposed text concerns latching/lock down mechanisms engaging properly. This statement is redundant with the requirements in §250.428, and its removal here would not change the requirement there regarding indications of inadequate cement jobs.	installing the casing string. ~~If there is an indication of an inadequate cement job, you must comply with § 250.428(c).~~
§250.423(b)	(b) If you run a liner that has a latching mechanism or lock down mechanism, you must ensure that the latching mechanisms or lock down mechanisms are engaged upon successfully installing the liner. If there is an indication of an inadequate cement job, you must comply with §250.428(c).	Industry agrees with proposed change but believe that the second sentence "If there is any indication of an inadequate cement job, you must comply with §250.428(c)." should be removed. There is no longer a reference to cementing outside of this sentence. The proposed text concerns latching/lock	(b) If you run a liner that has a latching mechanism or lock down mechanism, you must ensure that the latching mechanisms or lock down mechanisms are engaged upon successfully installing the liner.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
		down mechanisms engaging properly. This statement is redundant with the requirements in §250.428, and its removal here would not change the requirement there regarding indications of inadequate cement jobs.	
§250.427(b)	(b) While drilling, you must maintain the safe drilling margins identified in §250.414. When you cannot maintain the safe margins, you must suspend drilling operations and remedy the situation.	In instances where an operator encounters a lost circulation zone, that operator would need to remedy the situation to move forward. Particularly when the lost circulation zone is on bottom, drilling ahead to get through the lost circulation zone may be the safest option to restore the integrity of the well rather than suspending drilling operations altogether to remedy the situation. It is appropriate for	(b) While drilling, you must maintain the safe drilling margins identified in §250.414. When you cannot maintain the safe drilling margins, you must remedy the situation through the implementation of an approved plan (API BULLETIN 92L (92L) or analogous plan (AP)) or suspend drilling operations until the District reviews and approves proposed remedial actions, which may include limited drilling through a lost circulation zone.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
		operators to specify how they will remedy an anticipated loss of circulation on bottom in the well's DWOP or APD. If an operator experiences an unanticipated loss of circulation or a reduced drilling margin, the operator should provide notice and the operator's plan for remedying the issue to BSEE within a reasonable timeframe.	
§250.428(c)	If you encounter the following situation: (c) Have indication of inadequate cement job (such as unplanned lost returns, no cement returns to mudline or expected height, cement channeling, or failure of equipment), Then you must: (1) Locate the top of cement by: (i) Running a temperature survey; (ii) Running a cement evaluation log; (iii) Using tracers in the cement and logging them prior to drill out; or (iv) Using a combination of these techniques. (2) Determine if your cement job is inadequate. If your cement job is determined to be inadequate, refer to	Concerns to c (1) (iii). The use of tracers would be helpful. The concern is around the requirement to log prior to drill out. Some operators are creating extensive shoe tracks to avoid wet shoes and requiring logging be complete prior to drill out might create some inefficiencies that do not change the risk profile.	If you encounter the following situation: (c) Have indication of inadequate cement job (such as unplanned lost returns, no cement returns to mudline or expected height, cement channeling, or failure of equipment), Then you must: (1) Locate the top of cement by: (i) Running a temperature

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
	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.	Tracers are meant to be used when the losses are more likely, and TOC should be able to be found through the BHA MWD GR response.	survey; (ii) Running a cement evaluation log; (iii) Using tracers in the cement ~~and logging them prior to drill out~~; or (iv) Using a combination of these techniques. (2) Determine if your cement job is inadequate. If your cement job is determined to be inadequate, refer to paragraph (d) of this section. (3) If your cement job is determined to be adequate, report the results to the District Manager in your submitted WAR.
§250.428(d)	Comply with § 250.428(c)(1) and take remedial actions. The District Manager must review and approve all remedial actions either through a previously approved contingency plan within the permit or remedial actions included in a revised permit before you may take them, unless immediate actions must be taken to ensure the safety of the crew or to prevent a well-control event. If you complete any immediate action to ensure the safety of the crew or to prevent a well-control event, submit a description of the action to the District Manager when that action is complete. Any changes to the well program, that are not included in the approved permit, will require submittal of a certification by a	Industry agrees with the proposed changes. In part D, changes will allow for preapproval of contingency plans such as liner top squeezes, shoe squeezes, etc. in addition to the normal method of approval via RPD. This should help minimize rigging having idle time associated with RPD	Recommend adding "if necessary" in §250.428(d). I.e.: Comply with §250.428(c)(1), and take remedial actions, if necessary. The District Manager must review and approve all remedial actions either through a previously approved contingency plan within the permit or remedial

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
	professional engineer (PE) certifying that they have reviewed and approved the proposed changes. You must also meet any other requirements of the District Manager for remedial actions.	process.	actions included in a revised permit before you may take them, unless immediate actions must be taken to ensure the safety of the crew or to prevent a well-control event. If you complete any immediate action to ensure the safety of the crew or to prevent a well-control event, submit a description of the action to the District Manager when that action is complete. Any changes to the well program, that are not included in the approved permit, will require submittal of a certification by a professional engineer (PE) certifying that they have reviewed and approved the proposed changes. You must also meet any other requirements of the District Manager for remedial actions.
§250.433(b)	(b) For floating drilling operations with a subsea BOP stack, you must actuate the diverter system within 7 days after the previous actuation. For subsequent testing, you may partially actuate the	Industry agrees with the proposed change.	None. The proposed change is supported.

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	diverter element and a flow test is not required.		
§250.461(b)	(b) Survey requirements for directional well. You must conduct directional surveys on each directional well and digitally record the results. Surveys must give both inclination and azimuth at intervals not to exceed 500 feet during the normal course of drilling. Intervals during angle changing portions of the hole may not exceed 180 feet.	Industry agrees with the proposed change.	None. The proposed change is supported.
§250.462	What are the source control, containment, and collocated equipment requirements?	The proposed changes to 30 CFR 250.462 clarify the source control equipment requirements based on the operator's Regional Containment Demonstration (RCD) or Well Containment Plan (WCP). Similar to spill equipment (e.g. skimmers, sorbent boom, etc.), the majority of source control equipment has no other commercial purpose and is used solely for emergent containment operations, such as capping stacks, top hats and subsea dispersant wands. This unique containment equipment is maintained by specialty companies and readily	None. The proposed change is supported.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
		available for inspection at any time and maintained and stored for immediate use if an event occurs. Other equipment listed for source control that has broad commercial purpose, such as Remotely Operated Vehicles and vessels are readily available and frequently inspected and maintained for safe and efficient normal operations. Proposed revisions to paragraph (e)(3) would clarify that subsea utility equipment utilized solely for containment operations must be available for inspection at all times. Paragraph (e)(4) would also be revised to clarify that it is applicable only to collocated equipment identified in the Regional Containment Demonstration (RCD) or Well Containment	

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		Plan and not all collocated equipment. The proposed revisions to both paragraphs (e)(3) and (e)(4) would help ensure that the applicable respective equipment is available for inspection. BSEE recognizes that some of the equipment used for containment is used for other types of operations on the OCS and would be available for inspection when in use during other well operations.	
§250.518(e)(1)	(1) All permanently installed packers and bridge plugs qualified as mechanical barriers must comply with ANSI/API Spec. 11D1 (as incorporated by reference in §250.198).	Industry agrees with the proposed change as it would minimize the number of alternate equipment requests submitted to BSEE.	None. The proposed change is supported.
§250.519	Once you install your wellhead, you must meet the casing pressure management requirements of API RP 90 (as incorporated by reference in § 250.198) and the requirements of §§ 250.519 through 250.531. If there is a conflict between API RP 90 and the casing pressure requirements of this subpart, you must follow the requirements of this subpart.	Industry agrees with the proposed administrative change to update incorrect citations.	None. The proposed change is supported.

<table>
<tr><th>Proposed Regulation Reference</th><th>Proposed New Regulation Text</th><th>Comments</th><th>Recommended Industry Text</th></tr>
<tr><td>§250.522</td><td>A newly completed or recompleted well often has thermal casing pressure during initial startup. Bleeding casing pressure during the startup process is considered a normal and necessary operation to manage thermal casing pressure; therefore, you do not need to evaluate these operations as a casing diagnostic test. After 30 days of continuous production, the initial production startup operation is complete, and you must perform casing diagnostic testing as required in §§ 250.521 and 250.523.</td><td>Industry agrees with the proposed administrative change to update incorrect citations.</td><td>None. The proposed change is supported.</td></tr>
<tr><td>§250.525(d)</td><td>(d) Any well that has sustained casing pressure (SCP) and is bled down to prevent it from exceeding its MAWOP, except during initial startup operations described in §250.522;</td><td>Industry agrees with the proposed administrative change to update incorrect citations.</td><td>None. The proposed change is supported.</td></tr>
<tr><td>§250.526</td><td><table>
<tr><th>You must submit either . . .</th><th>to the appropriate . . .</th><th>and it must include . . .</th><th>You must also . . .</th></tr>
<tr><td>(a) a notification of corrective action; or,</td><td>District Manager and copy the Regional Supervisor, Field Operations,</td><td>requirements under § 250.527,</td><td>submit an Application for Permit to Modify or Corrective Action Plan within 30 days of the diagnostic test.</td></tr>
<tr><td>(b) a casing pressure request,</td><td>Regional Supervisor, Field Operations,</td><td>requirements under § 250.528.</td><td></td></tr>
</table></td><td>Industry agrees with the proposed administrative change to update incorrect citations.</td><td>None. The proposed change is supported.</td></tr>
<tr><td>§250.530(b)</td><td>(b) You must submit the casing diagnostic test data to the appropriate Regional Supervisor, Field Operations, within 14 days of completion of the diagnostic test required under §250.523(e).</td><td>Industry agrees with the proposed administrative change to update incorrect citations.</td><td>None. The proposed change is supported.</td></tr>
<tr><td>§250.601(m)</td><td>(m) Acid treatments</td><td>Industry agrees the proposed change is helpful in minimizing confusion about the definition of routine operations.</td><td>None. The proposed change is supported.</td></tr>
<tr><td>§250.616</td><td>[Reserved]</td><td>Industry agrees with the</td><td>None. The proposed change</td></tr>
</table>

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		proposed change.	is supported.
§250.619(e)(1)	(1) All permanently installed packers and bridge plugs qualified as mechanical barriers must comply with ANSI/API Spec. 11D1 (as incorporated by reference in §250.198). You must have two independent barriers, one being mechanical, in the exposed center wellbore prior to removing the tree and/or well control equipment;	Industry agrees the proposed change provides clarity as to when packers and bridge plugs need to be qualified as mechanical barriers.	None. The proposed change is supported.
§§250.720(a)(1) and (a)(3)	(a) * * * (1) The events that would cause you to interrupt operations and notify the District Manager include, but are not limited to, the following: (i) Evacuation of the rig crew; (ii) Inability to keep the rig on location; (iii) Repair to major rig or well-control equipment; (iv) Observed flow outside the well's casing (e.g., shallow water flow or bubbling); or (v) Impending National Weather Service-named tropical storm or hurricane. * * * * * (3) If you unlatch the BOP or LMRP: (i) Upon relatch of the BOP, you must test according to §250.734(b)(2), or (ii) Upon relatch of the LMRP, you must test according to §250.734(b)(3); and (iii) You must receive District Manager approval before resuming operations.	Industry agrees with the proposed change to codify existing BSEE policy and guidance. While we agree with the revision, we have concerns with the requirement in §250.734(b), incorporated here, to re-test the deadman systems when they have not been repaired or affected by the suspension. It is important to verify that the system is functional, but in cases where the system has not been modified, the previous test should be sufficient. Full discussion of the potential safety risk and proposed alternate	None. The proposed change is supported.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
		text is included below in §250.734(b).	
§250.720(d)	(d) For subsea completed wells with a tree installed, you must have the equipment and capabilities for intervention on those wells. All equipment utilized solely for intervention operations (e.g.. tree interface tools) must be readily available, maintained in accordance with OEM recommendations, and available for inspection by BSEE upon request.	Industry agrees with the inclusion of requirements for the location of required tools for well intervention operations. However, the industry believes the proposed text is overly prescriptive and does not consider the relative risk of active production wells and operators procedures and pressure management guidelines. Industry recommends that BSEE consider applying the following risk-based context to the subsea wells. 1. Is the reservoir pressure depleted to a pressure below the seawater hydrostatic pressure at the subsea wellhead? If the answer is yes, then	(d) For subsea completed wells with a tree installed, you must risk assess based on reservoir pressure, MAWHP, production annulus pressure management, and availability of BOP stack with standard intervention kit, and if dictated by the risk assessment, ensure that equipment for intervention operations (e.g., tree interface tools) is identified, available, and properly maintained. The risk assessment must be available for review by BSEE upon request.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
		sufficient mitigations are in place. 2. Is the well's current Maximum Anticipated Wellhead Pressure (MAWHP) reduced to a pressure below 50% of the initial well MAWHP, and does the operator have the ability to monitor the pressure in the production annulus (A annulus)? If the answer is yes, then sufficient mitigations are in place. 3. Does the well have the ability and the operator's annulus pressure management plan allow the production annulus (A annulus) to be bled to the production system? If the answer is yes, then sufficient mitigations are in place. 4. Can the operator utilize a BOP stack with an industry	

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
		standard intervention kit (e.g. the Q4000 with IRS), or existing equipment referenced in their well containment plans? If the answer is yes, then sufficient mitigations are in place. If an operator cannot demonstrate at least one of the risk criteria outlined above on an individual well or field basis, then an operator should develop an Intervention Readiness Plan (IRP). The IRP should address response actions required to respond to a potential release for the specific wells or fields identified. Industry can use the proposed criteria to determine whether sufficient mitigations are in place for individual wells / fields or a Readiness Plan is required. This approach	

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
		builds on and codifies effective pressure and well management programs existent in industry and ensures operators are ready to intervene, when the risk of an intervention is appropriate.	
§250.722(a)(2)	(2) Report the results of your evaluation to the District Manager and obtain approval of those results before resuming operations. Your report must include calculations that indicate the well's integrity is above the minimum safety factors, if an imaging tool or caliper is used. District Manager approval is not required to resume operations if you conducted a successful pressure test as approved in your permit. You must document the successful pressure test in the WAR.	Industry agrees with the change allowing for continued operations when a successful pressure test (as per the permit) is obtained.	None. The proposed change is supported.
§250.724(a)	(a) No later than April 29, 2019, when conducting well operations with a subsea BOP or with a surface BOP on a floating facility, or when operating in an high pressure high temperature (HPHT) environment, you must gather and monitor real-time well data using an independent, automatic, and continuous monitoring system capable of recording, storing, and transmitting data regarding the following: (1) The BOP control system; (2) The well's fluid handling system on the rig; and (3) The well's downhole conditions with the bottom hole assembly tools (if any tools are installed).	Industry has concerns with the scope of the rule which would result from the adoption of the proposed text. The proposed text would remove an existing boundary in the regulation limiting the scope of §250.724 to Applications for Permits to Drill (APDs). Industry recommends the addition of language defining RTM applications	(a) No later than April 29, 2019, when conducting well operations with a subsea BOP or with a surface BOP on a floating facility, as defined by API Standard 53 incorporated by reference in §250.198(h)(63), or when operating in an high pressure high temperature (HPHT) environment, you must gather and monitor real-time well data using an

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
		to those operations covered by API Standard 53 to clearly state, consistent with the current regulations and with the incorporation of Standard 53, 4th Edition, with its Addendum 1, which systems must be covered by an Operator's RTM plan. This would provide clarity on scope in the proposed rule consistent with current regulation. Industry also believes that the existing language in §250.724(a)(2), "well's fluid handling system on the rig" is potentially unclear as some fluid "handling systems" are not part of the active well barrier. For clarity, industry proposes changing the language to read as "well's active circulating system". The industry recommended text relies on standard industry definitions to demonstrate	independent, automatic, and continuous monitoring system capable of recording, storing, and transmitting data regarding the following: (1) The BOP control system; (2) The well's active fluid circulating system; and (3) The well's downhole conditions with the bottom hole assembly tools (if any tools are installed).

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
		the intent of the current regulations. Additionally, by focusing on the active system, the text of the rule would be aligned with standard industry vernacular for the primary fluid system that is relied on for well control. The most relevant volumes to trend in real time are the active, collectively the "active system". The current version "well's fluid handling system" could be inadvertently be interpreted as including other systems on the rig such as sand traps, reserve pits, storage pits, and offline volume. In this case, monitoring those systems could make it difficult to differentiate well behavior by diluting the well response over a larger volume and trending data that is not directly connected to the well. Each operator's RTM plan should address managing	

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
		the monitored pits as the active system on the rig changes. This is commonly managed in industry by the use of the pit volume totalizer (PVT) and flow measurement systems.	
§250.724(b)	Remove existing §250.724(b) and redesignate existing paragraph (c) with minor revisions as paragraph (b). (b) You must develop and implement a real-time monitoring plan. Your real-time monitoring plan, and all real-time monitoring data, must be made available to BSEE upon request. Your real-time monitoring plan must include the following: (1) A description of your real-time monitoring capabilities, including the types of the data collected; (2) A description of how your real-time monitoring data will be transmitted during operations, how the data will be labeled and monitored by qualified personnel, and how the data will be stored as required in §§250.740 and 250.741; (3) A description of your procedures for providing BSEE access, upon request, to your realtime monitoring data; (4) The qualifications of the personnel monitoring the data; (5) Your procedures for, and methods of, communication between rig personnel and the monitoring personnel; and (6) Actions to be taken if you lose any real-time monitoring capabilities or communications between rig personnel and monitoring personnel, and a protocol for how you will respond to any significant and/or prolonged interruption of monitoring capabilities or communications, including your protocol for notifying BSEE of any significant and/or prolonged interruptions.	Industry supports the removal from the rule of the current §250.724(b), allowing a greater degree for operators to develop RTM plans consistent with their specific operational risk, their governing principles, and SEMS procedures. Additionally, industry supports the removal of references to “onshore” from the existing rule. These changes retain the risk ownership of the operation and decision-making with the individual Operator.	None. The proposed change is supported.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.730(a)	(a) You must ensure that the BOP system and system components are designed, installed, maintained, inspected, tested, and used properly to ensure well control. The working-pressure rating of each BOP component (excluding annular(s)) must exceed MASP as defined for the operation. For a subsea BOP, the MASP must be taken at the mudline. The BOP system includes the BOP stack, control system, and any other associated system(s) and equipment. The BOP system and individual components must be able to perform their expected functions and be compatible with each other. Your BOP system must be capable of closing and sealing the wellbore in the event of flow due to a kick, including under anticipated flowing conditions for the specific well conditions, without losing ram closure time and sealing integrity due to the corrosiveness, volume, and abrasiveness of any fluids in the wellbore that the BOP system may encounter. Your BOP system must meet the following requirements: (1) The BOP requirements of API Standard 53 (incorporated by reference in § 250.198) and the requirements of §§ 250.733 through 250.739. If there is a conflict between API Standard 53 and the requirements of this subpart, you must follow the requirements of this subpart. (2) The provisions of the following industry standards (all incorporated by reference in § 250.198) that apply to BOP systems: (i) ANSI/API Spec. 6A; (ii) ANSI/API Spec. 16A; (iii) ANSI/API Spec. 16C; (iv) API Spec. 16D; and (v) ANSI/API Spec. 17D. (3) For surface and subsea BOPs, the pipe and variable bore rams	Industry agrees with the proposed change as it aligns the document with existing industry practices proven successful in Drilling activities worldwide.	None. The proposed change is supported.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
	installed in the BOP stack must be capable of effectively closing and sealing on the tubular body of any drill pipe, workstring, and tubing (excluding tubing with exterior control lines and flat packs) in the hole under MASP, as defined for the operation, with the proposed regulator settings of the BOP control system. (4) The current set of approved schematic drawings must be available on the rig and at an onshore location. If you make any modifications to the BOP or control system that will change your BSEE-approved schematic drawings, you must suspend operations until you obtain approval from the District Manager.		
§250.730(b)	(b) You must ensure that the design, fabrication, maintenance, and repair of your BOP system is in accordance with the requirements contained in this part, applicable Original Equipment Manufacturers (OEM) recommendations unless otherwise directed by BSEE, and recognized engineering practices. The training and qualification of repair and maintenance personnel must meet or exceed applicable OEM training recommendations unless otherwise directed by BSEE.	Planned and corrective maintenance is written by the Equipment Owner based on the OEM recommendation. The design, fabrication and remanufacture is the remit of the OEM or current equipment manufacturer. The proposed change is to ensure consistency with API 53. Maintenance is covered in §250.730(a).	(b) You must ensure that the design, fabrication, ~~maintenance~~ and ~~repair~~ remanufacture of your BOP system is in accordance with the requirements contained in this part, applicable Original Equipment Manufacturers (OEM) recommendations unless otherwise directed by BSEE, and recognized engineering practices. The training and qualification of repair and remanufacturing personnel must meet or exceed applicable OEM training recommendations unless otherwise directed by BSEE.
§250.730(c)	(c) You must follow the failure reporting procedures contained in	Industry appreciates the	(c) You must follow the

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
	API Standard 53, (incorporated by reference in § 250.198), and: (1) You must provide a written notice of equipment failure to BSEE, unless BSEE has designated a third party as provided in paragraph (d) of this section, and the manufacturer of such equipment within 30 days after the discovery and identification of the failure. A failure is any condition that prevents the equipment from meeting the functional specification. (2) You must ensure that an investigation and a failure analysis are started within 120 days of the failure to determine the cause of the failure and are completed within 120 days upon starting the investigation and failure analysis. You must also ensure that the results and any corrective action are documented. You must ensure that the analysis report is submitted to BSEE, unless BSEE has designated a third party as provided in paragraph (c)(4) of this section, as well as the manufacturer. (3) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such changes, report the design change or modified procedures in writing to BSEE, unless BSEE has designated a third party as provided in paragraph (c)(4) of this section. (4) BSEE may designate a third party to receive the data and reports on behalf of BSEE. If BSEE designates a third party, you must submit the data and reports to the designated third party.	additional time provided by the proposed changes (120 days from incident to 120 days from start of the investigation). Industry recognizes that not all failures will require a detailed investigation. However, industry is concerned that extenuating circumstances (operational or investigation related) may prevent the completion of the investigation within 120 days. Industry proposes that the rule provide a method for extending investigations that have been started but are not complete within the 120 days. The Operator would submit a status update to BSEE detailing the proress to date, reason(s) as to why the investigation is not completed, and a defined extension period.	failure reporting procedures contained in API Standard 53, (incorporated by reference in § 250.198), and: (1) You must provide a written notice of equipment failure to BSEE, unless BSEE has designated a third party as provided in paragraph (d) of this section, and the manufacturer of such equipment within 30 days after the discovery and identification of the failure. A failure is any condition that prevents the equipment from meeting the functional specification. (2) You must ensure that an investigation and a failure analysis are started within 120 days of the failure to determine the cause of the failure and are completed within 120 days upon starting the investigation and failure analysis. If the investigation cannot be completed within the 120-day period, you must submit a status update of the

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
			investigation. You must also ensure that the results and any corrective action are documented. You must ensure that the analysis report and any investigation status updates are submitted to BSEE, unless BSEE has designated a third party as provided in paragraph (c)(4) of this section, as well as the manufacturer. (3) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such changes, report the design change or modified procedures in writing to BSEE, unless BSEE has designated a third party as provided in paragraph (c)(4) of this section. (4) BSEE may designate a third party to receive the data and reports on behalf of

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
			BSEE. If BSEE designates a third party, you must submit the data and reports to the designated third party.
§250.730(d)	(d) If you plan to use a BOP stack manufactured after the effective date of this regulation, you must use one manufactured pursuant to an ANSI/API Spec. Q1 (as incorporated by reference in § 250.198) quality management system. Such quality management system must be certified by an entity that meets the requirements of ISO/IEC 17021-1 (as incorporated by reference in §250.198). (1) BSEE may consider accepting equipment manufactured under quality assurance programs other than ANSI/API Spec. Q1, provided you submit a request to the Chief, Office of Offshore Regulatory Programs for approval, containing relevant information about the alternative program. (2) You must submit this request to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, Virginia 20166.	Industry requests the addition of "or stack sub-assemblies" to provide clarity that the rule is covering the overall BOP Stack and the component assemblies contained within.	(d) If you plan to use a BOP stack and/or Stack sub-assemblies (covered under the specifications incorporated by reference in 250.198) manufactured after the effective date of this regulation, you must use one manufactured pursuant to an ANSI/API Spec. Q1 (as incorporated by reference in § 250.198) quality management system. Such quality management system must be certified by an entity that meets the requirements of ISO/IEC 17021-1 (as incorporated by reference in §250.198). (1) BSEE may consider accepting equipment manufactured under quality assurance programs other than ANSI/API Spec. Q1, provided you submit a request to the Chief, Office of Offshore Regulatory

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			Programs for approval, containing relevant information about the alternative program. (2) You must submit this request to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, Virginia 20166.
§250.731(a)(5)	(5) Control system pressure and regulator settings needed to close each ram BOP under MASP as defined for the operation;	Industry agrees with proposed change based on field testing.	None. The proposed change is supported.
§250.731(c)	Verification that: (1) Test data demonstrate the shear ram(s) will shear the drill pipe at the water depth as required in § 250.732; (2) The BOP was designed, tested, and maintained to perform under the maximum environmental and operational conditions anticipated to occur at the well; (3) The accumulator system has sufficient fluid to operate the BOP system without assistance from the charging system; and (4) If using a subsea BOP, a BOP in an HPHT environment as defined in § 250.804(b), or a surface BOP on a floating facility, the BOP has not been compromised or damaged from previous service.	Industry agrees with proposed change based on on-going verification, witnessing by independent third parties, and validation procedures which are in place. These practices have proved to be successful in Drilling activities worldwide.	None. The proposed change is supported.
§250.731(f)	MIA	Agree with proposed change based on on-going verification, I3P witnessing,	None. The proposed change is supported.

<table>
<tr><th>Proposed Regulation Reference</th><th>Proposed New Regulation Text</th><th>Comments</th><th>Recommended Industry Text</th></tr>
<tr><td></td><td></td><td>and validation procedures in place. These practices have proved to be successful in Drilling activities worldwide.</td><td></td></tr>
<tr><td>§250.732(a)(1)</td><td>(a) Prior to beginning any operation requiring the use of any BOP, you must submit verification by an independent third party and supporting documentation as required by this paragraph to the appropriate District Manager and Regional Supervisor.
<table>
<tr><th>You must submit verification and documentation related to:</th><th>That:</th></tr>
<tr><td>(1) Shear testing,</td><td>(i) Demonstrates that the BOP will shear the drill pipe and any electric-, wire-, and slick-line to be used in the well;</td></tr>
<tr><td></td><td>(ii) Demonstrates the use of test protocols and analysis that represent recognized engineering practices for ensuring the repeatability and reproducibility of the tests, and that the testing was performed by a facility that meets generally accepted quality assurance standards;</td></tr>
<tr><td></td><td>(iii) Provides a reasonable representation of field applications, taking into consideration the physical and mechanical properties of the drill pipe;</td></tr>
<tr><td></td><td>(iv) Demonstrates the shearing capacity of the BOP equipment to the physical and mechanical properties of the drill pipe; and</td></tr>
<tr><td></td><td>(v) Includes relevant testing results.</td></tr>
</table></td><td>Industry agrees with proposed change based on on-going verification, witnessing by independent third parties, and validation procedures which are in place. These practices have proved to be successful in Drilling activities worldwide.</td><td>None. The proposed change is supported.</td></tr>
<tr><td>§250.732(a)(2)</td><td><table>
<tr><th>You must submit verification and documentation related to:</th><th>That:</th></tr>
<tr><td>(2) Pressure integrity</td><td>(i) Shows that testing is conducted</td></tr>
</table></td><td>Industry proposes that “immediately” be removed</td><td><table>
<tr><th>You must submit verification</th><th>That:</th></tr>
</table></td></tr>
</table>

<table>
<tr><th>Proposed Regulation Reference</th><th>Proposed New Regulation Text</th><th>Comments</th><th>Recommended Industry Text</th></tr>
<tr><td></td><td><table><tr><td>testing, and</td><td>immediately after the shearing tests;</td></tr><tr><td></td><td>(ii) Demonstrates that the equipment will seal at the rated working pressures (RWP) of the BOP for 5 minutes; and</td></tr><tr><td></td><td>(iii) Includes all relevant test results.</td></tr></table></td><td>from the rule and that “after the shearing is completed and prior to opening the rams” be added as this will provide clarity to the requirement.

Industry supports using a 5-minute test as minimum requirement is in line with existing test data and has proved to be successful in Drilling activities worldwide.</td><td><table><tr><td>and documentation related to:</td><td></td></tr><tr><td>(2) Pressure integrity testing, and</td><td>(i) Shows that testing is conducted after the shearing is completed and prior to opening the rams;</td></tr><tr><td></td><td>(ii) Demonstrates that the equipment will seal at the rated working pressures (RWP) of the BOP for 5 minutes; and</td></tr><tr><td></td><td>(iii) Includes all relevant test results.</td></tr></table></td></tr>
<tr><td>§250.732(a)(3)</td><td><table><tr><th>You must submit verification and documentation related to:</th><th>That:</th></tr><tr><td>(3) Calculations</td><td>Include shearing and sealing pressures for all pipe to be used in the well including corrections for MASP.</td></tr></table></td><td>Industry agrees with the proposed change.</td><td>None. The proposed change is supported.</td></tr>
<tr><td>§250.732(b)</td><td>(b) The independent third-party must be a technical classification society, or a licensed professional engineering firm, or a registered professional engineer capable of providing the</td><td>Industry agrees with the proposed change based on existing shear testing</td><td>None. The proposed change is supported.</td></tr>
</table>

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<tr><th>Proposed Regulation Reference</th><th>Proposed New Regulation Text</th><th>Comments</th><th>Recommended Industry Text</th></tr>
<tr><td></td><td>required certifications and verifications.</td><td>demonstrating that the BOP is capable of shearing the required tubulars.</td><td></td></tr>
<tr><td>§250.732(c) & (d)</td><td>(c) For wells in an HPHT environment, as defined by § 250.804(b), you must submit verification by an independent third party that the independent third party conducted a comprehensive review of the BOP system and related equipment you propose to use. You must provide the independent third-party access to any facility associated with the BOP system or related equipment during the review process. You must submit the verifications required by this paragraph (c) to the appropriate District Manager and Regional Supervisor before you begin any operations in an HPHT environment with the proposed equipment.
<table>
<tr><th>You must submit:</th><th>Including:</th></tr>
<tr><td>(1) Verification that the independent third party conducted a detailed review of the design package to ensure that all critical components and systems meet recognized engineering practices,</td><td></td></tr>
<tr><td>(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,</td><td>(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.</td></tr>
<tr><td>(3) Verification that the BOP equipment will perform as designed in the temperature, pressure, and environment that will be encountered, and</td><td></td></tr>
<tr><td>(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.</td><td>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.</td></tr>
</table>
(d) You must make all documentation that supports the requirements of this section available to BSEE upon request.</td><td>Industry agrees with proposed change based on on-going verification, witnessing by independent third parties, and validation procedures which are in place. These practices have proved to be successful in Drilling activities worldwide.</td><td>None. The proposed change is supported.</td></tr>
<tr><td>§250.733(a)(1)</td><td>(1) The blind shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that include</td><td>Industry does not agree with BSEE’s assertion that “The alternative cutting</td><td>(1) Effective April 29, 2021, the blind shear rams (within the scope of API 16A</td></tr>
</table>

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
	heavy-weight pipe or collars), workstring, tubing and associated exterior control lines, and any electric-, wire-, and slick-line that is in the hole and sealing the wellbore after shearing.	device is no longer necessary because the currently commercially available shear rams have increased design capabilities, which are capable of shearing these types of lines." While rigs utilizing wire-, electric-, slick-line do have a method for cutting these lines, Industry wishes to clarify that BSEE's statement is not wholly accurate as the OEMs do not offer, and are not expected to offer, wireline cutting capability for all the BOP sizes and rated working pressures currently utilized in the GOM. OEMs do currently offer wireline shear & seal Blind Shear Rams for a range of BOPs, predominately 18-3/4" bore sizes. However, utilizing an 18-3/4" bore BOP is not possible for all	incorporated by reference in 250.198) must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that include heavy-weight pipe or collars), workstring, tubing, and any electric-, wire-, and slick-line that is in the hole and sealing the wellbore after shearing. If your blind shear rams are unable to cut any electric-, wire-, or slick-line under MASP as defined for the operation and seal the wellbore, you must use another device capable of shearing the lines before closing the BOP. This device must be available on the rig floor during operations that require their use.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
		applications because of limitations and/or restrictions for weight, size, and configuration. Accordingly, it will be necessary for BSEE and Industry work together to discuss the available options and limitations of their use. Industry believes it is appropriate to establish a minimum time period of 5 years from the original release of the WCR for design, testing, manufacture, and installation of the requested Blind Shear Rams for all known bore size and rated working pressure combinations that are available. Until these Rams are available, Industry must be allowed to continue to utilize the Alternative Cutting Device referenced in §250.733(a)(1) and	

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
		inclusive of the response to this item below. There are other available cutting device solutions that will cut wireline/etc. As the Cutting Device is part of a system-based approach for the Drilling Operation, the regulatory requirement for the Blind Shear Ram and the BOP Stack itself to be the sole device capable of cutting the wireline/etc is restrictive of innovation related to the intent of this requirement.	
§250.733(b)(1)	(1) For BOPs installed after April 29, 2021, follow the BOP requirements in § 250.734(a)(1).	Industry believes that this proposed change was intended to apply only to **NEW** floating production facilities.	(1) For BOPs installed on new floating production facilities installed after April 29, 2021, follow the BOP requirements in § 250.734(a)(1).
§250.733(e)	(e) Additional requirements for surface BOP systems used in well-completion, workover, and decommissioning operations. The minimum BOP system for well-completion, workover, and decommissioning operations must meet the appropriate standards from the following table:	Industry agrees with the proposed change. Industry recognizes and appreciates the deviation from drilling BOP classes and agrees with this wording, confident it does not adversely affect safety	None. The proposed change is supported.

<table>
<tr><th>Proposed Regulation Reference</th><th>Proposed New Regulation Text</th><th>Comments</th><th>Recommended Industry Text</th></tr>
<tr><td></td><td><table>
<tr><th>When . . .</th><th>The minimum BOP stack must include . . .</th></tr>
<tr><td>(1) The expected pressure is less than 5,000 psi,</td><td>Three BOPs consisting of an annular, one set of pipe rams, and one set of blind-shear rams.</td></tr>
<tr><td>(2) The expected pressure is 5,000 psi or greater or you use multiple tubing strings,</td><td>Four BOPs consisting of an annular, two sets of pipe rams, and one set of blind-shear rams.</td></tr>
<tr><td>(3) You handle multiple tubing strings simultaneously,</td><td>Four BOPs consisting of an annular, one set of pipe rams, one set of dual pipe rams, and one set of blind-shear rams.</td></tr>
<tr><td>(4) You use a tapered drill string,</td><td>At least one set of pipe rams that are capable of sealing around each size of drill string. If the expected pressure is greater than 5,000 psi, then you must have at least two sets of pipe rams that are capable of sealing around the larger size drill string. You may substitute one set of variable bore rams for two sets of pipe rams.</td></tr>
<tr><td>(5) You use a surface BOP on a floating facility,</td><td>The elements required by § 250.733(b)(1) of this part.</td></tr>
</table></td><td>considerations.</td><td></td></tr>
<tr><td>§250.734(a)(1)(ii)</td><td>(ii) A combination of the shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies such as heavy-weight pipe or collars), workstring, tubing and associated exterior control lines, appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric-, wire-, slick-line in the hole; under MASP. At least one shear ram must be capable of sealing the wellbore after shearing under MASP conditions as defined for the operation. Any non-sealing shear ram(s) must be installed below a sealing shear ram(s).</td><td>Industry agrees with the proposed change which is based on a previously published BSEE interpretation.</td><td>None. The proposed change is supported.</td></tr>
<tr><td>§250.734(a)(3)</td><td>The accumulator capacity must:
(i) Close each required shear ram, ram locks, one pipe ram, and disconnect the LMRP.
(ii) Have the capability to perform ROV functions within the required times outlined in API Standard 53 with ROV or flying leads.
(iii) No later than April 29, 2021, have bottles for the autoshear and deadman (which may be shared between those two systems)</td><td>Industry agrees with the proposed change based on alignment with API Std 53, 4th edition, with Addendum 1, and in recognition of its proper application and historical success of Subsea BOP</td><td>None. The proposed change is supported.</td></tr>
</table>

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
	to secure the wellbore. These bottles may also be utilized to perform the secondary control system functions (e.g., ROV or acoustic functions). (iv) Perform under MASP conditions as defined for the operation.	Stacks around the world.	
§250.734(a)(4)	The ROV must be capable of closing each shear ram, ram locks, one pipe ram, and disconnecting the LMRP under MASP conditions as defined for the operation. The ROV must be capable of performing these functions in the response times outlined in API Standard 53 (as incorporated by reference in §250.198). The ROV panels on the BOP and LMRP must be compliant with API RP 17H (as incorporated by reference in §250.198).	Industry agrees with removing the open function requirement from the ROV Panel. However, industry is not in agreement with the proposed text requiring that the ROV alone (without flying leads) must be capable of meeting the API S53 timing requirements. The text as written does not provide clarity as to whether the timing requirements can be met by the ROV alone or whether the ROV can meet these requirements by using a flying lead as allowed in .734(a)(3)(ii). Industry recommends that the timing requirements align with API Standard 53	The ROV must be capable of closing each shear ram, ram locks, one pipe ram, and disconnecting the LMRP under MASP conditions as defined for the operation. The ROV must be capable of performing these functions independently, via flying lead or external power source in the response times outlined in API Standard 53 (as incorporated by reference in §250.198). The ROV panels on the BOP and LMRP must be compliant with API RP 17H (as incorporated by reference in §250.198).

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
		and the prior references in the WCR with respect to the ROV capability. Industry is also concerned with BSEE's reference to compliance with API 17H 2nd edition, since API Standard 53 (see section 7.3.20.1.3) already covers this requirement. If the intention of this requirement is to ensure compatibility of all ROVs with all BOP Stack mounted ROV panels, then adherence to API 17H Type A, B, or C stab receptacles can meet this requirement and are dimensionally the same in both API RP 17H 1st and 2nd Edition.	
§250.734(a)(6)(iv)	(iv) Autoshear/deadman functions must close, at a minimum, two shear rams in sequence and be capable of performing their expected shearing and sealing action under MASP conditions as defined for the operation.	Industry agrees with the proposed change based on alignment with API Std 53 4th edition and proper application / historical success of Subsea BOP	None. The proposed change is supported.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
		Stacks around the world.	
§250.734(a)(16)	(16) Use a BOP system that has the following mechanisms and capabilities; If your control pods contain a subsea electronic module with batteries, a mechanism for personnel on the rig to monitor the state of charge of the subsea electronic module batteries in the BOP control pods	Industry agree with the proposed change to remove the existing §§250.734(a)(16)(i) & (ii).	None. The proposed change is supported.
§250.734(b)	(b) If you suspend operations to make repairs to any part of the subsea BOP system, you must stop operations at a safe downhole location. Before resuming operations, you must: (1) Submit a revised permit with a verification report from an independent third party documenting the repairs and that the BOP is fit for service; (2) Upon relatch of the BOP, perform an initial subsea BOP test in accordance with § 250.737(d)(4), including deadman in accordance with § 250.737(d)(12)(vi). If repairs take longer than 30 days, once the BOP is on deck, you must test in accordance with the requirements of § 250.737; (3) Upon relatch of the LMRP, you must test according to the following: (i) Pressure test riser connector/gasket in accordance with § 250.737(b) and (c); (ii) Pressure test choke and kill stabs at LMRP/BOP interface in accordance with § 250.737(b) and (c); (iii) Full function test of both pods and both control panels; (iv) Verify acoustic pod communication (if equipped); and (v) Deadman test with pressure test in accordance with §250.737(d)(12)(vi). (4) Receive approval from the District Manager.	Retesting the deadman subsea after a successful surface verification is not necessary every time the BOP or LMRP is latched to the wellhead (ex., weather suspensions, disconnect for tubing head spool installation, etc.). Doing so presents unnecessary risk to people, asset and the environment. Proposed that deadman retesting subsea only be required when repairs are made to or could impact the deadman circuit.	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 an independent third party documenting the repairs and that the BOP is fit for service; (2) Upon relatch of the BOP, perform an initial subsea BOP test in accordance with § 250.737(d)(4). Deadman test required on surface prior to redeployment and only required subsea if any repairs were made to the deadman circuit; (3) Upon relatch of the

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
			LMRP, you must test according to the following: (i) Pressure test riser connector/gasket in accordance with § 250.737(b) and (c); (ii) Pressure test choke and kill stabs at LMRP/BOP interface in accordance with § 250.737(b) and (c); (iii) Full function test of both pods and both control panels; (iv) Verify acoustic pod communication (if equipped); and (v) Deadman test with pressure test in accordance with §250.737(d)(12)(vi) if any repairs were made to the deadman circuit; and (4) Receive approval from the District Manager.
§250.735(a)	(a) An accumulator system (as specified in API Standard 53 and incorporated by reference in § 250.198). Your accumulator system must have the fluid volume capacity and appropriate pre-charge pressures in accordance with API Standard 53. If you supply the accumulator regulators by rig air and do not have a secondary source of pneumatic supply, you must equip the regulators with manual overrides or other devices to ensure capability of hydraulic operations if rig air is lost;	Industry agrees with the proposed change based on its alignment with API Std 53, 4th edition and proper application / historical success of Subsea BOP Stacks around the world.	None. The proposed change is supported.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.736(d)(5)	(5) When running casing, a safety valve in the open position available on the rig floor to fit the casing string being run in the hole. For subsea BOPs, the safety valve must be available on the rig floor if the length of casing being run exceeds the water depth, which would result in the casing being across the BOP stack and the rig floor prior to crossing over to the drill pipe running string;	Industry agrees with the proposed change based on proper application / historical success around the world.	None. The proposed change is supported.
§250.737(a)	BSEE has not proposed revision of this section.	Industry proposes BSEE adopt the 21-day test frequency in conformance with API Std 53, 4th edition. This test period ensures reliability of the sealing components and is based on industry studies to determine the appropriate test frequency to achieve the highest reliability considering wear and fatigue on systems. The change does not impact the weekly function test requirement, which is the most reliable determinant of system health.	Revise §250.737(a) to read as follows: (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; (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

<table>
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<tr><td></td><td></td><td></td><td>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;
(4) The District Manager may require more frequent testing if conditions or your BOP performance warrant.</td></tr>
<tr><td>§§250.737(b) & (c)</td><td>(b) Pressure test procedures. When you pressure test the BOP system, you must conduct a low-pressure test and a high-pressure test for each BOP component (excluding test rams and non-sealing shear rams). You must begin each test by conducting the low-pressure test then transition to the high-pressure test. Each individual pressure test must hold pressure long enough to demonstrate the tested component(s) holds the required pressure. The table in this paragraph (b) outlines your pressure test requirements.
<table>
<tr><th>You must conduct a . . .</th><th>According to the following procedures . . .</th></tr>
<tr><td>(1) Low-pressure test</td><td>All low-pressure tests must be between 250 and 350 psi. Any initial pressure above 350 psi must be bled back to a pressure between 250 and 350 psi before starting the test. If the initial pressure</td></tr>
</table></td><td>Would like the WCR to be consistent in requirements by a) aligning with testing requirements of API Std 53 and b) allowing the use of alternative pressure testing systems that can determine test validity in less than 5 minutes.

Would like clarity with respect to statement in .737(b) where the text states "…test must hold pressure long enough to demonstrate the tested</td><td>(b) Pressure test procedures. When you pressure test the BOP system, you must conduct a low-pressure test and a high-pressure test for each BOP component. You must begin each test by conducting the low-pressure test then transition to the high-pressure test. Each individual pressure test must be consistent with paragraph (c). The table in this paragraph (b) outlines your pressure test requirements.</td></tr>
</table>

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<tr>
<td></td>
<td><table>
<tr><td></td><td>exceeds 500 psi, you must bleed back to zero and reinitiate the test.</td></tr>
<tr><td>(2) High-pressure test for blind shear ram-type BOPs, ram-type BOPs, the choke manifold, outside of all choke and kill side outlet valves (and annular gas bleed valves for subsea BOP), inside of all choke and kill side outlet valves below uppermost ram, and other BOP components</td><td>(i) The high-pressure test must equal the RWP of the equipment or be 500 psi greater than your calculated MASP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP plus 500 psi, the District Manager must have approved those test pressures in your permit.
(ii) The blind shear ram (BSR) must be tested to:
(A) MASP plus 500 psi for the hole section to which it is exposed; or
(B) Full well MASP plus 500 psi on initial latch up and all subsequent BSR pressure tests can be done to the casing/liner test pressure for the applicable hole section.
(iii) The choke and kill side outlet valves must be tested to, except as provided in paragraph (d)(13) of this section:
(A) MASP plus 500 psi for the hole section to which it is exposed; or
(B) Full well MASP plus 500 psi on initial latch up and all subsequent pressure tests can be done to the casing/liner test pressure for the applicable hole section.</td></tr>
<tr><td>(3) High-pressure test for annular-type BOPs, inside of choke or kill valves (and annular gas bleed valves for subsea BOP) above the uppermost ram BOP</td><td>The high-pressure test must equal 70 percent of the RWP of the equipment or be 500 psi greater than your calculated MASP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP plus 500 psi, the District Manager must</td></tr>
</table></td>
<td>component(s) holds the required pressure.”

Vs

Section .737(c) where the text states “Each test must hold the required pressure for 5 minutes,…”</td>
<td>(c) Duration of pressure test. Each Subsea BOP system test must hold the required pressure for 5 minutes, which must be recorded on a chart not exceeding 4 hours or a digital recorder. However, for surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable ~~if recorded on a chart not exceeding 4 hours, or on a digital recorder.~~ The recorded test pressures must be within the middle half of the chart range, i.e., cannot be within the lower or upper one-fourth of the chart range. If the equipment does not hold the required pressure during a test, you must correct the problem and retest the affected component(s).</td>
</tr>
</table>

<table>
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<tr><td></td><td><table><tr><td></td><td>have approved those test pressures in your APD.</td></tr></table></td><td></td><td></td></tr>
<tr><td>§§250.737(d)(2), (d)(3), (d)(3)(v), (d)(4)(i), (d)(4)(iii), (d)(4)(v)</td><td>BOP System Testing Requirements<table>
<tr><th>You must…</th><th>Additional requirements…</th></tr>
<tr><td>(2) * * *</td><td>(ii) Contact the District Manager at least 72 hours prior to beginning the initial test to allow BSEE representative(s) to witness testing.</td></tr>
<tr><td>(3) * * *</td><td>(iii) Contact the District Manager at least 72 hours prior to beginning the stump test to allow BSEE representative(s) to witness testing</td></tr>
<tr><td></td><td>(v) You must follow paragraphs (b) and (c) of this section. Pressure testing of each ram and annular component is only required once.</td></tr>
<tr><td>(4) * * *</td><td>(i) You must begin the initial subsea BOP test on the seafloor within 30 days of the stump test.</td></tr>
<tr><td colspan="2">* * * * * * *</td></tr>
<tr><td></td><td>(iii) You must pressure test well-control rams and annulars according to paragraphs (b) and (c) of this section.</td></tr>
<tr><td colspan="2">* * * * * * *</td></tr>
<tr><td></td><td>(v) You must test and verify closure of at least one set of rams during the initial subsea test through a ROV hot stab. You must confirm closure of the selected ram through the ROV hot stab with a 1,000 psi pressure test for 5 minutes.</td></tr>
</table></td><td>Industry agrees with proposed changes, with one exception to 250.737(d)(iv).</td><td>250.737(d)(iv) You must verify closure of all critical ROV intervention functions as defined in API 53 during predeployment testing.

Any additional installed ROV intervention functions must be verified per the equipment owner’s maintenance program but not to exceed once per year.</td></tr>
<tr><td>250.737(d)(5)(ii)</td><td><table>
<tr><th>You must…</th><th>Additional requirements…</th></tr>
<tr><td>(5) Alternate tests between control stations</td><td>(i) For two complete BOP control stations you must:
(A) Designate a primary and secondary station;
(B) Alternate testing between the primary and secondary control stations on a weekly basis; and
(C) For a subsea BOP, develop an alternating testing schedule to ensure the primary and</td></tr>
</table></td><td>Industry agrees with the removal of “and monthly thereafter” from the rule.

Industry would like to see additional alignment between the proposed rule and API Std 53 Section</td><td><table>
<tr><th>You must…</th><th>Additional requirements…</th></tr>
<tr><td>(5) Alternate tests between control stations</td><td>(i) For two complete BOP control stations you must:
(A) Designate a primary and</td></tr>
</table></td></tr>
</table>

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
	secondary control stations will function each pod. (ii) Remote panels where all BOP functions are not included (e.g., life boat panels) must be function-tested upon the initial BOP tests.	7.6.5.1.4 which states "If installed, remote panels where all BOP functions are not included (e.g. lifeboat panels, etc.) shall be function tested in accordance with the equipment owner's procedures." The inclusion of "in accordance with the equipment owner's procedures" allows the user to conduct the test with the BOP on-deck and does not alter the effectiveness or intent of the proposed BSEE text.	secondary station; (B) Alternate testing between the primary and secondary control stations on a weekly basis; and (C) For a subsea BOP, develop an alternating testing schedule to ensure the primary and secondary control stations will function each pod. (ii) Remote panels where all BOP functions are not included (e.g., life boat panels) must be function-tested in accordance with the equipment owner's procedures during the stump (pre-deployment) BOP tests.
§§250.737(d)12(iv), (d)(12)(vi) & (d)(13)	**You must…** | **Additional requirements…** (12) * * * | (iv) Following the deadman system test on the seafloor you must document the final remaining pressure of the subsea accumulator system. * * * * * * * (vi) You must confirm closure of the BSR(s) with a 1,000 psi pressure test for 5 minutes.	Industry agrees with the proposed changes.	None. The proposed change is supported.

<table>
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<tr><td></td><td><table><tr><td colspan="2">* * * * * * *</td></tr><tr><td>(13) Pressure test the choke and kill side outlet valves</td><td>According to paragraph (b), except as follows:
(i) For 14 day BOP testing, test the wellbore side of the choke and kill side outlet valves above the uppermost pipe ram to the approved annular test pressure. Choke and kill side outlet valves below the uppermost pipe ram must be tested to MASP plus 500 psi for the applicable hole section.
(ii) For the 30 day BSR testing, test the wellbore side of the choke and kill side outlet valves between the upper most pipe ram and the upper most ram, to the casing/liner test pressure or annular test pressure, whichever is greater.
(iii) For BOPs with only one choke and kill side outlet valve, you are only required to pressure test the choke and kill side outlet valves from the wellbore side.</td></tr></table></td><td></td><td></td></tr>
<tr><td>§250.738(b)</td><td><table><tr><th>If you encounter the following situation:</th><th>Then you must . . .</th></tr><tr><td>b) * * *</td><td>(4) You must submit a report from an independent third party to the
District Manager certifying that the BOP is fit for service</td></tr></table></td><td>Industry agrees with the proposed changes.</td><td>None. The proposed change is supported.</td></tr>
<tr><td>§250.738(f)</td><td><table><tr><th>If you encounter the following situation:</th><th>Then you must . . .</th></tr><tr><td>(f) Plan to install casing rams or casing shear rams in a surface BOP stack;</td><td>Before running casing, perform a shell test to the permit approved test pressure of the BOP component above the casing ram/casing shear. If this installation was not included in your approved permit, and changes the BOP configuration approved in the APD or APM, you must notify and receive approval from the District Manager</td></tr></table></td><td>Industry agrees with the intent of this revision but would likely clarity added regarding the timing/location of the test.</td><td><table><tr><th>If you encounter the following situation:</th><th>Then you must . . .</th></tr><tr><td>(f) Plan to install casing rams or casing shear rams in a surface</td><td>Before running casing, perform a shell test to the permit approved test pressure of the BOP component</td></tr></table></td></tr>
</table>

<table>
<tr><th>Proposed Regulation Reference</th><th>Proposed New Regulation Text</th><th>Comments</th><th>Recommended Industry Text</th></tr>
<tr><td></td><td></td><td></td><td><table><tr><td>BOP stack;</td><td>above the casing ram/casing shear. Initial pressure testing shall be performed before operations commence. 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.</td></tr></table></td></tr>
<tr><td>§§250.738(i), (m) & (o)</td><td><table><tr><th>If you encounter the following situation:</th><th>Then you must . . .</th></tr><tr><td>(i) You activate any shear ram and pipe or casing is sheared;</td><td>Retrieve, physically inspect, and conduct a full pressure test of the BOP stack after the situation is fully controlled. You must submit to the District Manager a report from an independent third party certifying that the BOP is fit to return to service.</td></tr><tr><td colspan="2">* * * * * * *</td></tr><tr><td>(m) Plan to utilize any other circulating or ancillary equipment (e.g., but not limited to, subsea isolation device, subsea accumulator module,</td><td>Contact the District Manager and request approval in your APD or APM. Your request must include a report from an independent third party on the equipment's design and suitability for its intended use as well as any other information required by the District Manager. The District Manager may impose any conditions regarding the equipment's</td></tr></table></td><td>Industry agrees with the proposed changes.</td><td>None. The proposed change is supported.</td></tr>
</table>

<table>
<tr><th>Proposed Regulation Reference</th><th>Proposed New Regulation Text</th><th>Comments</th><th>Recommended Industry Text</th></tr>
<tr><td></td><td><table>
<tr><td>or gas handler) that is in addition to the equipment required in this subpart;</td><td>capabilities, operation, and testing.</td></tr>
<tr><td colspan="2">* * * * * * *</td></tr>
<tr><td>(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);</td><td>Comply with all testing, maintenance, and inspection requirements in this subpart that are applicable to those well-control components. If any redundant component fails a test, you must submit a report from an independent third party that describes the failure and confirms that there is no impact on the BOP that will make it unfit for well-control purposes. You must submit this report to the District Manager and receive approval before resuming operations. The District Manager may require you to provide additional information as needed to clarify or evaluate your report.</td></tr>
<tr><td colspan="2">* * * * * * *</td></tr>
</table></td><td></td><td></td></tr>
<tr><td>§250.739(b) introductory text</td><td>(b) A major, detailed inspection of the well control system components (including but not limited to riser, BOP, LMRP, and control pods) must be performed every 5 years. This major inspection may be performed in phased intervals. You must track and document all system and component inspection dates. These records must be available on the rig. An independent third party is required to review the inspection results and must compile a detailed report of the inspection results, including descriptions of any problems and how they were corrected. You must make these reports available to BSEE upon request. This major inspection must be performed every 5 years from the following applicable dates, whichever is later:</td><td>Industry agrees with the proposed changes.</td><td>None. The proposed change is supported.</td></tr>
</table>

<table>
<tr><th>Proposed Regulation Reference</th><th>Proposed New Regulation Text</th><th>Comments</th><th>Recommended Industry Text</th></tr>
<tr><td>250.741(b)(2)</td><td>BSEE has not proposed revision of this section.</td><td>Industry proposes that BSEE include in the revised rule, a revision to 250.741, that real-time monitoring data retention be adjusted from §250.741(b) two years to §250.741(a) 90 days from completion of the operation. The primary value of the RTM data is in diagnostic of ongoing operation and response to incidents. These scenarios occur during or immediately following conclusion of the operation. Requiring operators to retain the real-time monitoring data for 2 years presents a burden on resource and data storage considering the volume of RTM data anticipated without materially increasing the safety of operations or the ability of industry or BSEE to learn from events. Industry remains supportive of retaining the rest of §250.741(b) with a</td><td><table>
<tr><th>You must keep records relating to . . .</th><th>Until . . .</th></tr>
<tr><td>(a) Drilling and real-time monitoring data;</td><td>90 days after you complete operations.</td></tr>
<tr><td>(b) Casing and liner pressure tests, diverter tests, BOP tests~~,~~ ~~and real-time monitoring data~~;</td><td>2 years after the completion of operations.</td></tr>
<tr><td>(c) Completion of a well or of any workover activity that materially alters the completion configuration or affects a hydrocarbon-bearing zone.</td><td>You permanently plug and abandon the well or until you assign the lease and forward the records to the assignee.</td></tr>
</table></td></tr>
</table>

<table>
<tr><th>Proposed Regulation Reference</th><th>Proposed New Regulation Text</th><th>Comments</th><th>Recommended Industry Text</th></tr>
<tr><td></td><td></td><td>2-year requirement. The barrier verification, casing test, and BOP test data retains value for diagnostic purposes beyond the immediate completion of the operation and should continue to be retained as prescribed in the current regulations.</td><td></td></tr>
<tr><td>§ 250.750</td><td></td><td></td><td></td></tr>
<tr><td>§ 250.751</td><td></td><td></td><td></td></tr>
<tr><td>§250.1703</td><td>(b) Permanently plug all wells. Packers and bridge plugs used as qualified mechanical barriers must comply with ANSI/API Spec. 11D1 (as incorporated by reference in § 250.198). You must have two independent barriers, one being mechanical, in the exposed center wellbore prior to removing the tree and/or well control equipment;</td><td>Industry agrees with the changes. They provide clarity as to when packers and bridge plugs need to be qualified as mechanical barriers.</td><td>None. The proposed change is supported.</td></tr>
<tr><td>§250.1704(g)(4) & (h)(2)</td><td><table>
<tr><th>Decommissioning applications and reports</th><th>When to submit</th><th>Instructions</th></tr>
<tr><td>* * * * * * *</td><td></td><td></td></tr>
<tr><td>(g) * * *</td><td>(4) Within 30 days after you complete site clearance verification activities,</td><td>Include information required under § 250.1743(a).</td></tr>
<tr><td>(h) * * *</td><td>(2) Within 30 days after completion of decommissioning activity,</td><td>Include information required under §§ 250.1712 and 250.1721.</td></tr>
<tr><td>* * * * * * *</td><td></td><td></td></tr>
</table></td><td>Industry agrees with the change.</td><td>None. The proposed change is supported.</td></tr>
<tr><td>§250.1706</td><td>Remove and reserve</td><td>Industry agrees with the change.</td><td>None. The proposed change is supported.</td></tr>
</table>

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.1716(b)	(3) The water depth is greater than 1,000 feet.	Industry agrees with the change.	None. The proposed change is supported.
§250.1722(d) introductory text	(d) Within 30 days after you complete the trawling test described in paragraph (c) of this section, submit a report to the appropriate District Manager using form BSEE-0125, End of Operations Report (EOR) that includes the following:	Industry agrees with the change.	None. The proposed change is supported.

Questions posed by BSEE related to BOP Equipment and Drilling Margin		
Proposed Regulation Reference	**Proposed Question**	**Recommended Industry Response**
§250.198	<u>API Standard 53 – Edition to Incorporate:</u> At this time, BSEE does not propose to incorporate the API Standard 53 addendum into this proposed rule. However, BSEE is considering incorporating the API Standard 53 addendum in the final rule. BSEE is specifically soliciting comments on whether the API Standard 53 addendum should be included within the documents incorporated by reference. Please provide reasons for your position. If your comment addresses anticipated monetary or operational benefits associated with using the API Standard 53 addendum, please provide any available supporting data.	Industry's opinion is that the final rule should incorporate the latest released edition of API Standard 53 at the time of its publishing. In this case this is likely to be API Standard 53 4th Edition with its Addendum 1, issued in July 2016. A large portion of the GOM install base is already in compliance with API Standard 53 4th Edition w/ Addendum & Errata (July 2016). This addendum was compiled, reviewed, and approved by Industry representatives from Operators, Equipment Owners, OEMs, Independent Third Parties, and Service Companies within the API community. The addendum and errata provided clarity to existing text and increases operational safety and reliability. Industry would urge the agency to consider how the 5th Edition of API Standard 53 can be expeditiously incorporated into its regulation once it is published.
§250.730	<u>General req's for BOP systems & components - Failures:</u> Based upon the unknown situations that could arise around the completion of the failure analysis and availability of the equipment, BSEE is specifically soliciting comments about whether specifying a completion date for the failure analysis is appropriate and if so whether 120 days from the commencement of the analysis is appropriate. Please provide reasons for your position and any applicable associated data.	We appreciate the additional time provided by the proposed changes (120 days from incident to 120 days from start of the investigation). We recognize that not all failures will require a detailed investigation. However, we are concerned that extenuating circumstances (operational or investigation related) may prevent the completion of the investigation within 120 days. Industry proposes that BSEE allow a method for extending the completion dated for investigations that have been started but are not complete within the 120 days. In such cases, industry suggests the operator

		submit a status update to BSEE detailing the progress to date and reason(s) as to why the investigation is not completed.
§250.733	<u>Requirements for Surface BOP Stack – Alt Cutting Device:</u> This rulemaking would revise paragraph (a)(1) by removing the reference to an extended time for compliance with exterior control line shearing requirements under the original WCR, which BSEE anticipates will have run and no longer warrant reference in the regulations by the time a final rule is promulgated. BSEE also proposes to remove the requirement to have an alternative cutting device used for shearing electric-, wire-, or slick-line if your blind shear rams are unable to cut and seal under maximum anticipated surface pressure (MASP). The alternative cutting device is no longer necessary because the currently commercially available shear rams have increased design capabilities, which are capable of shearing these types of lines. BSEE is aware of concerns regarding the removal of the alternative cutting device option. Therefore, BSEE is considering other options in the final rule, such as keeping the alternative cutting device provisions in the regulations or extending the compliance date to allow the use of the alternative cutting devices until a more appropriate date when the surface stack shear rams can be upgraded to shear electric-, wire-, or slick-line. A. BSEE is specifically soliciting comments about the effectiveness of using an alternative cutting device and whether BSEE should continue to allow its use. B. Additionally, BSEE is also specifically soliciting comments on how long it would take for surface stack shear rams to be upgraded to shear electric-, wire-, or slick-line. Please provide reasons for your	Industry does not concur with BSEE's conclusion that the provisions for alternative cutting devices can be removed "because the currently commercially available shear rams … are capable of shearing these types of lines." While rigs utilizing wire-, electric-, slick-line do have a method for cutting these lines, we wish to clarify that BSEE's statement is not completely accurate as the OEMs do not offer wireline cutting capability for all BOP sizes and rated working pressures currently utilized in the GOM. OEMs do currently offer wireline shear & seal Blind Shear Rams for a range of BOPs, predominately 18-3/4" bore sizes. However, utilizing an 18-3/4" bore BOP is not possible for all applications because of limitations and/or restrictions for weight, size, and configuration. Therefore, we propose that BSEE and Industry work together to discuss the available options and limitations of their use. Industry requests a minimum time period of 5 years from the original release of the WCR for design, testing, manufacture, and installation of the requested Blind Shear Rams for all known bore size and rated working pressure combinations that are available. Until these Rams are available, Industry will utilize the Alternative Cutting Device referenced in §250.733(a)(1).

	position and any applicable associated data.	There are other cutting device solutions that will cut wireline/etc available. As the Cutting Device is part of a system-based approach for the Drilling Operation, the regulatory requirement for the Blind Shear Ram and the BOP Stack itself to be the sole device capable of cutting the wireline/etc is restrictive of innovation related to the intent of this requirement.
§250.734	Requirements for Subsea BOP System - Centering: BSEE believes that operators will continue to substitute new components for old ones to comply with the still-required increased shearing capability provisions of the original WCR. BSEE is aware of many technological advancements in shearing ram designs and capabilities. BSEE expects the shear rams to shear pipe or wire in any position within the wellbore; however, BSEE is specifically soliciting comments about the effectiveness of requiring shear rams to center pipe or wire while shearing or requiring shear rams to have the capability to shear any pipe or wire in the hole without a separate centering mechanism. Another option BSEE is considering is retaining the centering mechanism requirements, but expressly providing that the shear rams with these capabilities satisfy the requirements. Please provide reasons for your position and any applicable associated data.	Industry agrees with the proposed rule change to remove the existing §§250.734(a)(16)(i) and (ii). Industry does not believe that that the WCR should provide prescriptive design requirements for the Shear Ram itself: The performance standards for such equipment are adequately addressed in API 16A 4th Edition, which should, along with its subsequent editions, serve as the basis for the agency's regulations going forward.
Section III	Additional Comments Solicited – BOP Testing Frequency A. BSEE is requesting comments on whether the BOP testing interval should be 7 days, 14 days, or 21 days for all types of operations including drilling, completions, workovers, and decommissioning. B. BSEE is also requesting comments on the specific cost and operational implications of each testing interval to further its consideration of the issue.	Propose: A: Testing Duration (7, 14, or 21 days) Industry requests that BSEE align the proposed changes to the Well Control Rule with the 21-day testing interval outlined in API Standard 53 4th Edition (July 2016). This 21-day period has proven to provide assurance of a safe and reliable system without causing premature wear on the equipment. The existing 14-day regulation

	The industry and BSEE currently rely on function and hydrostatic tests to verify the performance of BOP equipment in the field. These tests have traditionally been the primary method of verifying the capability of in-service equipment. In recent years, the industry has raised concerns related to the benefits of pressure and functional testing of subsea BOPs when compared to the costs and potential operational issues. BSEE requests comments on the adequacy of the current functional and pressure test requirements in predicting the performance of this equipment in subsequent drilling operations. C. Under what circumstances or environments should the testing frequency be increased or decreased? BSEE is aware of potential technologies that may improve the operability and reliability of BOP systems. D. Are there additional technologies, processes, or procedures that can be used to supplement existing requirements and provide additional assurances related to the performance of this equipment? Please provide supporting reasons and data for your responses.	requirement results in an additional 53% of testing over a 12-month period with a corresponding increase in wear of seals and packers. <u>B: Cost and Operation Implications</u> Previously submitted Joint Trades sponsored Economic Study remains valid for this issue. <u>C: Circumstances or Environments based Frequency</u> Industry believes that the testing frequency of API Standard 53 4th Edition (July 2016) is the optimum requirement for typical worldwide operations. <u>D: Technology, Processes, Procedures for Additional Assurance</u> The 21-day testing period of API Standard 53 (July 2016) aligns with the global practice and capabilities of the existing technology installed and utilized in the GOM. Industry and BSEE recognize that there are technologies that exist, or are in development, that can provide the operator, owner, and OEM with data regarding the equipment's performance. The combination of existing technologies, API Standard 53 failure reporting, and the potential use of emerging technologies may lead to product and process improvements aiding reliability and the goal of further improved safety. As these technologies become more widely proven, Industry will continue to review the test frequency requirement within future revisions of API Standard 53.

<table>
<tr><td>§250.414</td><td>BSEE request comment on replacing it with a more performance-based standard under which the approved safe drilling margin is established on a case-by-case basis for each well.</td><td rowspan="3">Industry welcomes the opportunity to propose an engineered performance-based standard for the establishment of appropriate safe drilling margins thru the well permitting process. Evaluation and analysis of industry data of wells drilled demonstrates that operators have safely planned and drilled sections of wells below the current default 0.5 ppg drilling margin.

The industry has a good record of using hydraulic modeling techniques to plan the working drilling margin required to drill a hole section, and while drilling, actively control downhole wellbore pressure between the pore pressure and the expected shoe pressure integrity test or the lowest estimated fracture gradient. The hydraulic models consider factors including cutting loads, fluid temperature and rheology, drill string and wellbore configuration, drill string rotation speed and flowrates. The hydraulic models are calibrated to</td></tr>
<tr><td>§250.414</td><td>BSEE also request comment on potentially providing for a different drilling margin or multiple drilling margins that are specific to the conditions in which the wells are drilled, such as if the well is drilling in deep water or shallow water.</td></tr>
<tr><td>§250.414</td><td>BSEE further request comment on whether removal of a specific reference to a 0.5 ppg standard from the regulation may be appropriate.</td></tr>
</table>

§250.414	BSEE also request comment on the criteria that BSEE could use to apply alternative approaches, such as an operator demonstrating that a well is a development well as opposed to an exploratory well.	historic data. The use of real time downhole pressure while drilling (PWD) tools allows the operator to confirm model accuracy. While drilling the hole section, drilling parameters are actively managed to keep the circulating and static mud density within the planned drilling margin. Since 2010, the modeling software and computing resource utilized to build accurate models has improved significantly. The use of this technology has improved safety and will continue to meet or exceed regulatory requirements. Industry proposes that a Supplemental Drilling Margin Information Sheet (attached) be submitted as part of the permitting process. This plan will outline the expected drilling margin for each section based on engineering work using hydraulic models. Industry experience in managing drilling margin risk has demonstrated that the primary safety risk factors are: the presence of hydrocarbons; potential for flow; and the consequence of losses. A stable column of fluid is a primary well control barrier in drilling operations. This engineered approach, consistent with the requirements of the CFR, is applicable in shallow water or deepwater wells and exploration or development wells. There are reasonable situations where margins less than 0.5ppg can be safe when considering the full fluid system and the described risk factors. The operator will manage downhole pressures for each section within the approved drilling margin plan. Drilling can continue while the operator can manage downhole ECDs below the shoe pressure integrity test or the lowest estimated fracture gradient for the section. Equivalent downhole mud weight will be kept above the

		estimated pore pressure. District Manager approval is required if the approved plan cannot be maintained.
§250.414	BSEE request comment on what supplemental data would provide an adequate level of justification for deviating from the 0.5 ppg drilling margin under identified circumstances. Etc……	As discussed above, the engineering, performance-based approach does not support the 0.5 ppg drilling margin. As specified in comments submitted by industry in reference to §250.414 (c) and as shown on the accompanying spreadsheet (Supplemental Drilling Margin Information Sheet) a deviation is irrelevant.
§250.414	BSEE also requests comment on whether there are situations where drilling can continue prior to receiving alternative safe drilling margin approval from BSEE.	As discussed above, the engineering, performance-based approach necessitates BSEE approval.

§250.414	BSEE request comment on 1) whether there are situations where, despite not being able to maintain the approved safe drilling margin, an operator continued drilling with an alternative drilling margin creates little risk. 2) the criteria that BSEE should use to define those situations and available alternative drilling margins. 3) what level of follow-up reporting (.....) would be appropriate.	Industry has provided comments and recommended text changes for §250.414(c). Industry members believe that should the BSEE accept the proposed text and accompanying spreadsheet details for the Well Control Rule, then, industry could work with the BSEE in further development of an audit process similar to that required for Cementing using the 65-2 document.
§250.414	BSEE is specifically soliciting comments about the effectiveness of the use of related analogous data and how the pore pressure and fracture gradient are determined without related analogous data. Please provide reasons for your position.	Pore pressure and fracture gradients are not determined on GoM wells without the use of some type of related analogous data such as well data, seismic data and/or other geological data. In addition, there are region specific overburden/pore pressure/fracture gradient models and standard work flows used in conjunction with seismic data for regions without any nearby well control. Operators are responsible for identifying the appropriate analogous data for each well and evaluating their applicability.

RV0.6

Supplemental Drilling Margin Information Sheet

1. OPERATOR NAME **Oil Company A**	5. WELL NAME *(Proposed)* 001	6. TYPE OF WELL ■ EXPLORATORY □ DEVELOPMENT	11. WATER DEPTH (ft) 4,028	12. ELEVATION KB (ft) 82
2. API WELL NO. *(Proposed) (12 Digits)* | 3. BOTTOM LEASE NO. *(Proposed)*	7. SIDETRACK NO. 00	8. BYPASS NO. *(Proposed)* 00		
4. TOTAL DEPTH *(Proposed)* ftMD 28,500 ftTVD 26,000	9. RIG NAME OOC Drill 1	10. RIG TYPE DP Drill Ship		

13. ENGINEERING DATA

Hole Size (in) (decimals)	Liner, Casing, Jet Pipe	Casing Size (in) (decimals)	Casing Depth (feet KB) MD / TVD	Drilling Fluid Type (Oil Base, Water Base, Synthetic)	§250.414 (c) (1) (i) Estimated Pore Pressure (ppg)	§250.414 (c) (1) (i) Equivalent Downhole Mud Weight (ppg)	§250.414 (c) (1) (ii) ECD (ppg)	§250.414 (c) (1) (ii) Lowest Estimated Fracture Gradient (ppg)	§250.414 (c) (1) (ii) Pressure Integrity Test (ppg)	Hydraulic Modeling: Software Name & Version	Hydraulic Modeling: Depth modelled (MD kb)	Other Documentation (Such as risk modeling data, related analog well data, seismic data)	§250.427 (b) API BULLETIN 92L (API 92L) or Analogous Plan (AP)	Comments
Jetted	Drive Pipe	**38**	3,970 3,970	Seawater										Riserless[1]
32.5	Conductor	**28**	6,300 6,300	Seawater										Riserless[1]
26	Surface Casing	**22**	7,000 7,000	Seawater										Riserless[1]
21	Intermediate Liner	**18**	8,500 8,500	SBM									API 92L/AP	
19	Intermediate Liner	**16**	11,729 11,729	SBM									API 92L/AP	
17.5	Protective Casing	**14**	20,200 19,490	SBM									API 92L/AP	
14.5	Protective Liner	**11.75**	22,300 21,179	SBM								e.g risk assessment, more recent and relevant analogous data, updated geological environmental data	API 92L/AP	e.g. Developed field and have significant data to support ECD modeling.
8.5	Open Hole	**-**	28,500 26,000	SBM									API 92L/AP	

Instructions and comments:
Complete the table for all hole sections.