

S. HRG. 114-404

**THE WELL CONTROL RULE AND OTHER REGULA-
TIONS RELATED TO OFFSHORE OIL AND GAS
PRODUCTION**

HEARING

BEFORE THE

COMMITTEE ON

ENERGY AND NATURAL RESOURCES

UNITED STATES SENATE

ONE HUNDRED FOURTEENTH CONGRESS

FIRST SESSION

DECEMBER 1, 2015



Printed for the use of the
Committee on Energy and Natural Resources

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THE WELL CONTROL RULE AND OTHER REGULATIONS RELATED TO OFFSHORE OIL AND GAS PRODUCTION

TUESDAY, DECEMBER 1, 2015

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The Committee met, pursuant to notice, at 10:07 a.m. in Room SD-366, Dirksen Senate Office Building, Hon. Lisa Murkowski, Chairman of the Committee, presiding.

OPENING STATEMENT OF HON. LISA MURKOWSKI, U.S. SENATOR FROM ALASKA

The CHAIRMAN. Good morning. The committee will come to order. I would like to welcome our panel here this morning as we begin our oversight hearing on offshore oil and gas regulations.

Offshore oil and gas production, of course, is an issue of national importance, not merely a topic for the coastal states that support it. According to the Office of Natural Resources Revenue, Federal offshore production tops one million barrels of crude oil per day and one trillion cubic feet of natural gas per year.

Those volumes are sizable, but we have seen a decline as a share of overall domestic production during this Administration. Since 2009, Federal offshore oil production is basically flat at best, while Federal offshore gas production has been cut in half.

A lot of us believe that our offshore production could and should be higher than it is today, a lot of us believe that more production would be good for our economy and for our security, and a lot of us are concerned that the offshore regulatory system has too often held projects back—my State of Alaska is probably Exhibit A, case in point.

No one here will suggest that offshore production should go unregulated or that safety should ever be anything except a top priority, yet it is also fair to examine whether our offshore regulators are striking the right balance and actually designing rules that will meet their objectives.

Which brings us to the focus of today's hearing, and that is the well control rule, and a series of related rules that govern offshore production in Federal areas. The stated aim of the well control rule, to ensure the safety of oil and gas operations offshore, to prevent incidents like the Macondo spill from ever happening again, is certainly one that I share.

The well control rule is, at its core, an extremely technical document, better suited perhaps to engineers than certainly to Senators here. As the committee with jurisdiction over the agency that issued the rule, however, we still need to do what we can to ensure that it will actually enhance the safety of offshore productions and operations. On that front, it appears that we have considerable cause for concern.

Over the past several months, many seasoned veterans of offshore exploration and production have submitted comments for the record about various aspects of the well control rule, as proposed. These experts have raised concerns over mandatory drilling margins, blowout preventer specifications, real-time monitoring, and more. They suggest in their comments that, if left unaddressed, these requirements may actually increase the risk of a catastrophic accident, actually taking us in the wrong direction.

When industry veterans come forward to express concern about a rule's impact on safety and not on the regulatory burden that a rule would impose or the jobs or the production it could cost, but safety, then I think it is something that we should all be paying attention to.

I also want to make a final point on Alaska. I have been deeply disturbed, and I have said so quite publicly, regarding the Administration's handling of our Arctic resources. The regulatory maze imposed from Washington, DC created a situation in which successful exploration of Alaska's offshore was an uphill battle every step of the way.

We have now seen two companies pull out of an area on our Outer Continental Shelf that holds an estimated 24 billion barrels of oil and 104 trillion cubic feet of natural gas, and again where there is very, very strong local support for development. Now, we all know that the physical environment in the Arctic is tough, but it was not the environment that prompted these decisions. It was, to a large degree, the regulatory environment which continues to deteriorate.

I believe that a new paradigm is in order, one that recognizes the Federal offshore areas in the Arctic are a "frontier play" worthy of a modern, adaptable leasing structure designed to help, than rather to block, exploration. So I think you could probably expect more from me on this, as well as the committee.

With that, I turn to Senator Cantwell for her comments.

STATEMENT OF HON. MARIA CANTWELL, U.S. SENATOR FROM WASHINGTON

Senator CANTWELL. Thank you, Madam Chair, and thank you for holding this hearing. I also want to welcome the witnesses today to share their insight on this proposed well control rule.

Safety and environmental protection in energy production are important, especially in fragile ocean ecosystems, so I am glad that there is much interest in this rule today.

I think it is safe to say that the BP Deepwater Horizon explosion and oil spill was a human, economic, and ecological disaster of epic proportions. Eleven members of the crew were killed in an explosion and 17 others were injured, and oil spewed into the ocean for

nearly three months, a mile below the surface, before the magnitude of the damage became apparent.

It is estimated that 171 million gallons—that is, five million barrels—of oil escaped the uncontrolled well. So people and wildlife were exposed to oil and toxic chemical dispersants. Unfortunately, local economies and critical habitats of the Gulf were impacted.

It is clear now that this disaster could have been avoided and that multiple Blue Ribbon panels all concluded that the immediate cause of the blowout can be traced to a series of systematic failures in risk management and a broken safety culture.

Another contributing factor—government mismanagement—has been addressed through the reorganization of the Minerals Management Service into separate leasing, revenue, and enforcement bureaus. There have been changes to the way these new regulatory bodies interact with the industry they oversee to ensure that they avoid the circumstances where we have regulators captured by the industries they are supposed to regulate.

Setting aside organizational issues, the well control rule at issue today will address the other primary cause of the Deepwater Horizon disaster—inadequate risk management and safety oversight—by codifying the advances made by industry experts and regulators over the last five years.

We have made progress since Deepwater Horizon, but “loss of well control” remains an issue. In fact, since 2010, there have been 23 separate “loss of well control” incidents. The Administration estimates that we experience between six and eight of these incidents a year. We cannot afford these kinds of risks. The residents, the environment, the coastal economies, the taxpayers, not even the oil and gas industry can afford a repeat of the Deepwater Horizon disaster.

So although none of the events have been as significant as Deepwater Horizon, the fact that these keep happening only emphasizes the need for comprehensive, robust safety standards, which this rule provides. Although hindsight is 20/20 and we cannot reverse what happened on the Deepwater Horizon, we can work to not repeat history, and that is what this rule is trying to help.

This rule has been more than five years in the making with input from more than 50 different companies. Its goal is to define safe drilling practices, operational expectations for drilling equipment, performance criteria for blowout preventers, and increasing monitoring and verification.

I know that performance-based requirements allow industry experts who know these systems to best comply with the requirements in the most efficient ways, but in order for these to work, industry has to uphold their end of the bargain. We must also improve transparency through mechanisms like data sharing when things go wrong so that regulators and industry can adapt and face these new challenges. I am sure we are going to hear more about that today.

In summary, the Administration has worked in good faith to ensure everyone’s voice is heard. They extended the comment period and hosted workshops. I think that they have done their due diligence on being inclusive. It is time to move forward on this process with the final rule.

I recognize that no safety standard can be 100 percent failsafe, but we can work to make incremental improvements to oil production procedures and safety. I urge my colleagues to recognize that we still have serious gaps in oil spill response technology. The Coast Guard, NOAA, and other experts have testified to this fact again and again and again. The United States is not prepared to handle a large spill like the Deepwater Horizon. Our oil spill response infrastructure has not been updated for decades.

As we drill for oil in deeper and deeper water, the Coast Guard has repeatedly stated that we do not have the ability to clean up oil on ice. This is a huge concern. Not only do we have Arctic exploration occurring in U.S. waters, but also our neighboring countries are investing heavily in Arctic exploration. As we open up new habitats to oil and gas and transportation, including in the Arctic, new science and technologies are sorely needed.

So that is why we need to strengthen NOAA's role in the Department of the Interior's leasing and sales decisions. And certainly NOAA should have essentially the same input as members of the public in discussing these issues.

It is clear today that we have many challenges in front of us, but I think that this rule should be finalized without further delay. I look forward to hearing from the witnesses and their testimony.

Thank you, Madam Chair.

[The prepared statement of Senator Cantwell follows:]

**U.S. Senate Committee on Energy and Natural Resources
December 1, 2015 Hearing: The Well Control Rule
and Other Regulations Related to Offshore Oil and Gas Production**

**Senator Cantwell
Statement for the Record**

Thank you, Madam Chair, and thank you for holding this hearing. I want to welcome to the witnesses today to share their insight on this proposed Well Control Rule. Safety and environmental protections in energy production are important, especially in fragile ocean ecosystems, so I'm glad that there is much interest in this rule today.

I think it's safe to say that the BP Deepwater Horizon explosion and oil spill was a human, economic and ecological disaster of epic proportions. Eleven members of the crew were killed in the explosion and 17 others were injured. Oil spewed into the ocean for nearly 3 months, a mile below the surface, before the magnitude of the damage became apparent.

It's estimated that 171 million gallons — that is, 5 million barrels — of oil escaped the uncontrolled well.

People and wildlife were exposed to oil and toxic chemical dispersants. And unfortunately, local economies and critical habitats in the Gulf were impacted.

It's clear now that this disaster could have been avoided. Multiple Blue Ribbon panels all have concluded that the immediate cause of the blowout can be traced to a series of systematic failures in risk management and a broken safety culture.

Another contributing factor — government mismanagement — has been addressed through the reorganization of the Minerals Management Service, into separate leasing, revenue and enforcement bureaus. There have been changes to the way these new regulatory bodies interact with the industry they oversee to ensure that they avoid circumstances where we have regulators captured by the industries they regulate.

**U.S. Senate Committee on Energy and Natural Resources
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Setting aside organizational issues, the Well Control Rule at issue today will address the other primary causes of the Deepwater Horizon disaster — inadequate risk management and safety oversight — by codifying the advances made by industry experts and regulators over the last 5 years.

We've made progress since Deepwater Horizon, but 'loss of well control' remains an issue. In fact, since 2010, there have been 23 separate 'loss of well control' incidents. The administration estimates that we experience between 6 and 8 of these incidents each year.

We can't afford this kind of risk. The residents, the environment, the coastal economies, the taxpayers — even the offshore oil and gas industry — cannot afford a repeat of the Deepwater Horizon disaster.

Although none of the events since have been as significant as Deepwater Horizon, the fact that these keep happening only emphasizes the need for comprehensive and robust safety standards — which this rule provides.

Although hindsight is 20/20 and we can't reverse what happened at Deepwater Horizon, we can work to not repeat history. That's what this rule is trying to help with.

This rule has been more than 5 years in the making, with input from more than 50 companies. Its goal is to define safe drilling practices, operational expectations for drilling equipment, performance criteria for blowout preventers, and increased monitoring and verification.

I know that performance-based requirements allow the industry experts who know these systems best to comply with the spirit of the requirement in the most efficient and safest way. But in order for these to work, industry has to hold up their end of the bargain. We must also improve transparency, through mechanisms like data sharing when things go wrong, so that regulators and industry can adapt to face these new challenges.

**U.S. Senate Committee on Energy and Natural Resources
December 1, 2015 Hearing: The Well Control Rule
and Other Regulations Related to Offshore Oil and Gas Production**

I'm sure we're going to hear more about that today.

In summary, the administration has worked in good faith to ensure everyone's voice is heard. They extended the comment period, hosted workshops and have engaged with third-party groups.

I think they've done their due diligence on being inclusive. It's time to move forward with the process and finalize this rule.

I recognize that no safety standard can be 100 percent fail-safe, but we can work to make incremental improvements to oil production procedures and safety. So, I urge my colleagues to recognize that we still have serious gaps in oil spill response technology.

The Coast Guard, NOAA (National Oceanic and Atmospheric Administration) and oil spill experts have testified time and time again—the United States is not prepared to handle a large oil spill—like the big spills we've seen in this country.

Our oil spill response infrastructure has not been updated in decades.

And yet we're moving into deeper and deeper water and going after oil in increasingly challenging settings like the Arctic.

The Coast Guard has repeatedly stated that we do not have the ability to clean up oil in ice. That is a huge concern when not only do we have Arctic exploration occurring in U.S. waters, but also our neighboring countries are investing heavily in oil production there. And with new habitats open to oil and gas production and transportation, including the Arctic, these new technologies are sorely needed.

**U.S. Senate Committee on Energy and Natural Resources
December 1, 2015 Hearing: The Well Control Rule
and Other Regulations Related to Offshore Oil and Gas Production**

That's why we need to strengthen NOAA's role in the Department of the Interior's leasing and sales decisions. Currently, NOAA has essentially the same input as any member of the public in discussing these issues.

It is clear today that we have many challenges in front of us. But I think that this rule should be finalized without further delay.

I look forward to hearing from the witnesses today and their testimony.

Thank you, Madam Chair.

The CHAIRMAN. Thank you, Senator Cantwell.

With that, we will turn to our panel. We will begin with Mr. Brian Salerno. Mr. Salerno is the Director for the Bureau of Safety and Environmental Enforcement, affectionately known as “Bessie,” at the Department of the Interior.

He will be followed by Mr. Erik Milito. Erik is the Director for the American Petroleum Institute. We welcome him back to the committee.

Next we have, Dr. Mark Rockel, who is the Principal Consultant for Ramboll Environ, and rounding out the panel this morning we have Ms. Jacqueline Savitz, who is Vice President of U.S. Oceans for Oceana.

Welcome to the committee. Mr. Salerno, if you would like to lead off. We would ask you to keep your comments to five minutes, and your full testimony will be incorporated as part of the record.

STATEMENT OF BRIAN SALERNO, DIRECTOR, BUREAU OF SAFETY AND ENVIRONMENTAL ENFORCEMENT, U.S. DEPARTMENT OF THE INTERIOR

Mr. SALERNO. Yes, ma’am. Chairman Murkowski, Ranking Member Cantwell, members of the committee, thank you for the opportunity to appear today to discuss the proposed well control rule and other regulations related to offshore oil and gas production.

The last time I testified before this committee was nearly five years ago after the Deepwater Horizon tragedy. My purpose then, as a Coast Guard flag officer, was to focus on the nation’s response to that disaster. Today, I appear in support of initiatives to reduce the risk of such an event from occurring again.

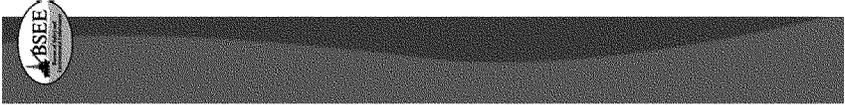
As you know, the Bureau that I now direct was formed after the Deepwater Horizon tragedy for the purpose of promoting safe operations and environmentally sound development of the nation’s offshore energy resources. The proposed rules being examined today were developed with these purposes in mind.

The proposed well control rule is an outgrowth of an unprecedented amount of analysis and critical thought that followed the Macondo blowout. The circumstances of that tragedy are well known, including a terrible loss of human life, widespread environmental damage, and economic harm to several states and to other industries such as fishing and tourism.

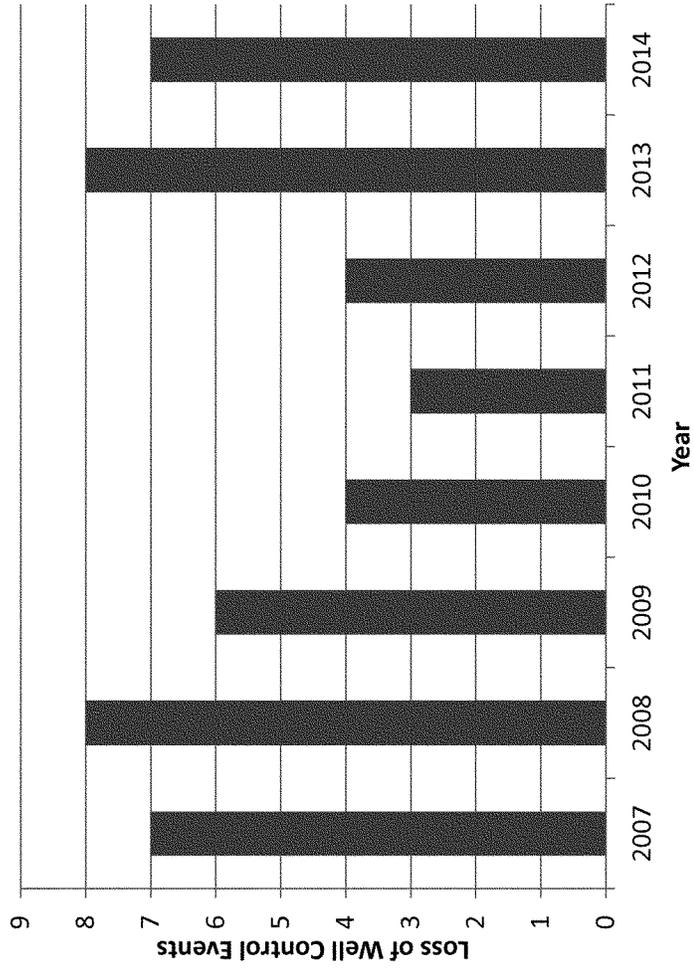
The numerous investigations, which were conducted in the aftermath of the blowout and which are referenced in my written testimony, resulted in over 400 recommendations to the Bureau with approximately 160 related to blowout preventers, well design, and safe well operations. The proposed well control rule synthesizes and incorporates many of these recommendations. It also adopts ten industry standards, all of this in an effort to reduce risk across all phases of drilling activity.

The pressing need for the well control rule is demonstrated by the fact that incidents involving losses of well control continue to occur, and they occur at the same rate as they did before the Macondo blowout. You can see from the chart behind me that in 2013 and 2014 alone there were a combined total of 15 incidents where control of the well was lost.

[The information referred to follows:]



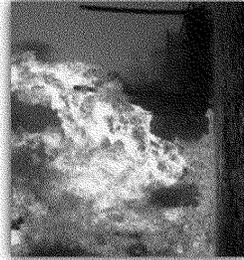
U.S. OCS Loss of Well Control Events (2007-2014)



Some of these developed into serious situations such as the 2013 blowout at the Walter Oil & Gas facility.
[The information referred to follows:]



January 16, 2012



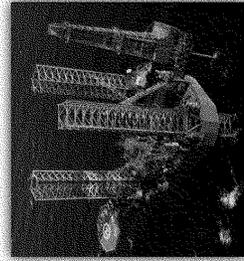
**Chevron
Blowout & Explosion**

Location: Nigeria

Water Depth: 40 feet

2 deaths, total rig loss,
oil spill

February 10, 2013



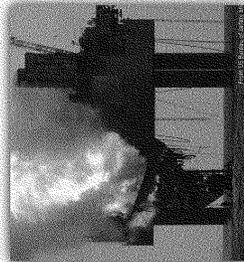
**Apache Loss of Well
Control**

Location: Gulf of Mexico

Water Depth: 218 feet

Gas leak, rig evacuation,
failed downhole
equipment

July 23, 2013



**Walter Oil & Gas
Blowout**

Location: Gulf of Mexico

Water Depth: 154 feet

Rig evacuation, fire, total
rig loss

In that case, all 44 workers were fortunately evacuated safely; however, the fire lasted for over 72 hours and the rig was completely destroyed, resulting in a financial loss approaching \$60 million.

In developing the proposed rule, BSEE sought input and advice from a wide variety of sources. In addition to the various post-Macondo studies and the associated recommendations, there were workshops, listening sessions, and information exchanges. All told, BSEE conducted over 50 meetings with various companies, trade associations, and other stakeholders.

Following publication of the proposed rule in April 2015, BSEE extended the original 60-day comment period by an additional 30 days to provide added opportunity for interested parties to comment. As a result, BSEE received over 5,000 pages of technical comments from over 170 comments.

We are still in the deliberative stage of the process where we review each of the comments and determine if and how language from the proposed rule should be modified. As part of this process, we are taking into account the technical concerns that have been expressed about safe drilling margins, blowout preventer inspections, accumulator capacity, and real-time monitoring, among others.

We are also reviewing the concerns we have heard regarding the use of prescriptive language and about the potential for unintended consequences. All of that is being considered in the deliberative process.

Shifting just for a moment to another rule of interest to this committee, the proposed Arctic rule, it was developed following a process of technical development and stakeholder engagement similar to the well control rule. In developing the Arctic rule, we and our sister agency, BOEM, held numerous public meetings and other outreach activities. We received well over 100,000 formal comments. BSEE and BOEM are currently reviewing those comments.

We are committed to putting out good rules which will raise the bar on safety, improve environmental protection, and which will be realistic and achievable for the industry. The comments that are now under consideration for both of these rules provide ample feedback to help us achieve all of those objectives.

This concludes my formal statement, and I look forward to your questions.

[The prepared statement of Mr. Salerno follows:]

**STATEMENT OF BRIAN SALERNO
DIRECTOR, BUREAU OF SAFETY AND ENVIRONMENTAL ENFORCEMENT
UNITED STATES DEPARTMENT OF THE INTERIOR
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE**

December 1, 2015

Chairman Murkowski, Ranking Member Cantwell, and members of the Committee, thank you for the opportunity to appear here today to discuss the Bureau of Safety and Environmental Enforcement's (BSEE) proposed Well Control Rule and other regulations related to offshore oil and gas production.

The proposed Well Control Rule is an outgrowth of an unprecedented amount of analysis and critical thought that followed the Macondo blowout and resulting consequences of the *Deepwater Horizon* tragedy. Many words have been spoken and written about avoiding another *Deepwater Horizon* incident and learning lessons that can help us prevent such tragedies. Perhaps this use of shorthand loses sight of the horrific details of April 20, 2010. On that night, the crew of the *Deepwater Horizon* was finishing work after drilling the Macondo exploratory well. The crew had one step to complete before it could move off of the well – temporary abandonment of the well. At just before 10:00PM, an undetected influx of hydrocarbons escalated into a blowout. When the well blew out, a mixture of hydrocarbons, mud, and water rained down on the workers on the rig floor. Very quickly, hydrocarbons that had flowed onto the rig floor ignited in two separate fiery explosions. Hydrocarbons continued to flow from the well and fueled the fire that continued to burn until the rig sank on April 22. Eleven men died and 16 were injured in the explosion and fire on the *Deepwater Horizon* that evening. Over the next 87 days, millions of barrels of oil flowed from the out-of-control Macondo well into the Gulf of Mexico.

Following the Macondo blowout, numerous investigations were conducted, including a

joint investigation by the Department of the Interior and the Department of Homeland Security¹, an investigation by the National Academy of Engineering², a report by the Council on Environmental Quality³, and an investigation by a National Commission⁴ formed by the President. These investigations and reports made clear that the loss of life on April 20, 2010 and the subsequent pollution of the Gulf of Mexico were the result of poor risk management, last minute changes to the operational plan, failure to observe and respond to critical indicators, inadequate well control response, and insufficient training by companies of individuals responsible for drilling the Macondo well. In particular, BP and Transocean failed in myriad ways to protect the lives of those onboard and to prevent the environmental catastrophe that ultimately occurred. The tragic events of April 20, 2010 showed the dire consequences that can result when companies fail to implement a culture of safety that assesses and mitigates risk. The tragedy that has become synonymous with the *Deepwater Horizon* was preventable.

The various investigations and reports that took place after the *Deepwater Horizon* tragedy resulted in recommendations regarding blowout preventers, well design, cementing, well integrity testing, kick detection and response, real-time monitoring of well operations, and other areas. The Well Control Rule synthesizes and incorporates a variety of these recommendations in an effort to reduce risks across all phases of drilling operations. This rule will be a critical component of BSEE's efforts, writ large, to drive down risks associated with offshore operations.

The need for the Well Control Rule is demonstrated by the fact that loss of well control

¹ The Bureau of Ocean Energy Management, Regulation and Enforcement, U.S. Department of the Interior, *Report Regarding the Causes of the April 20, 2010 Macondo Well Blowout* (Sep. 2011), http://www.bsee.gov/uploadedFiles/BSEE/BSEE_Newsroom/Publications_Library/OCS_Archives/DeepwaterHorizon/BOEMRE%20Final%20DWH%20Sept2011.pdf; United States Coast Guard, U.S. Department of Homeland Security, *Report of Investigation into the Circumstances Surrounding the Explosion, Fire, Sinking, and Loss of Eleven Crew Members Aboard the Mobile Offshore Drilling Unit Deepwater Horizon in the Gulf of Mexico – April 20, 2010* (Sep. 2011),

http://www.bsee.gov/uploadedFiles/BSEE/BSEE_Newsroom/Publications_Library/OCS_Archives/DeepwaterHorizon/2_DeepwaterHorizon_ROI_USCG_Volume%20I_20110707_redacted_final.pdf.

² National Academy of Engineering and National Research Council (NAE/NRC), *Macondo Well-Deepwater Horizon Blowout* (Dec. 2011), <http://www.nae.edu/Publications/Reports/53926.aspx>.

³ Council on Environmental Quality, *Report Regarding the Mineral Management Service's National Environmental Policy Act Policies, Practices, and Procedures as They Relate to Outer Continental Shelf Oil and Gas Exploration and Development* (Aug 2010),

https://ceq.doe.gov/current_developments/docs/CEQ_Report_Reviewing_MMS_OCS_NEPA_Implementation.pdf.

⁴ National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, *Deep Water: The Gulf Oil Disaster and the Future of Offshore Drilling* (Jan. 2011), <http://www.gpo.gov/fdsys/pkg/GPO-OILCOMMISSION/pdf/GPO-OILCOMMISSION.pdf>.

(LWC) incidents are happening at the same rate five years after the Macondo blowout as they were before. In 2013 and 2014, there were eight and seven LWC incidents per year, respectively – a rate on par with pre-Macondo losses of well control.⁵ These represent LWC in all water depths. Some of these LWC incidents have resulted in blowouts, such as the 2013 Walter Oil and Gas incident in which a loss of well control resulted in a blowout that caused a massive explosion and fire on the rig. All 44 workers were safely evacuated, but the fire lasted over 72 hours and the rig was completely destroyed, resulting in a financial loss approaching \$60 million. It was determined that this incident occurred due to the crew's inability to identify critical well control indicators and the failure of critical well control equipment. The Incident Report published about the Walter blowout identified numerous points throughout the drilling operation where things could have been much worse.⁶ Blowouts like these can easily lead to much larger incidents that pose a significant risk to human life and can cause serious damage to the environment. It is abundantly clear that despite post-Macondo improvements in safety and technological advancements, there are still issues that must be addressed in order to see an appreciable decrease in dangerous loss of well control incidents. The proposed Well Control Rule represents a concerted effort to address these issues and reduce risk offshore.

The Well Control Rule is an important pillar of BSEE's ongoing efforts to promote safe and environmentally responsible operations. This rule, which is in the process of being revised to address comments and suggestions made in response to the publication of the proposed version, includes safety enhancements in well design, cementing, blowout preventer maintenance and operations, real-time monitoring, and a number of other provisions. The Rule seeks to mitigate or eliminate different types of risks associated with drilling activities in several ways. First, the rule implements many of the recommendations related to well-control equipment and fill gaps in the regulatory program. It calls for increases in the performance and reliability of well-control equipment, with particular focus on blowout preventers. It improves regulatory oversight of the design, fabrication, maintenance, inspection, and reporting requirements for critical equipment. It also seeks to gain information on leading and lagging indicators of BOP

⁵ See Attachment 1. Also available at http://www.bsee.gov/uploadedFiles/BSEE/BSEE_Newsroom/Publications_Library/Annual_Report/BSEE%202014%20Annual%20Report.pdf.

⁶ See Bureau of Safety and Environmental Enforcement, U.S. Department of the Interior, *Investigation of Loss of Well Control and Fire South Timbalier Area Block 220, Well No. A-3 OCS-G24980 – 23 July 2013* (July 2015), http://www.bsee.gov/uploadedFiles/BSEE/Enforcement/Accidents_and_Incidents/Panel_Investigation_Reports/ST%20220%20Panel%20Report9_8_2015.pdf.

component failures and identify trends in those failures and help prevent accidents. Finally, the rule ensures that industry uses recognized engineering practices as well as innovative technology and techniques to increase overall safety.

BSEE began drafting the Well Control Rule following the release of numerous investigative reports on the *Deepwater Horizon* disaster that made specific suggestions on modifications to existing rules. BSEE considered all of more than 400 recommendations, conducted workshops with industry participants, and engaged all stakeholders about how its regulations could be modified to address the risks that were exposed on April 20, 2010, when 11 lives were lost and millions of barrels of oil were spilled into the Gulf of Mexico. The Well Control Rule is the culmination of a significant amount of analysis and input by many acclaimed engineers, scientists, investigators, management systems specialists, and experts from a variety of other disciplines. From the very beginning of the rulemaking process, industry and other stakeholders have been directly and substantially involved and engaged – through workshops, listening sessions, information exchanges, and formal and informal communications. Prior to releasing the proposed rule, BSEE conducted over 50 meetings with various companies, trade associations, regulators, and other stakeholders. After issuing the proposed rule in April 2015, BSEE extended the original 60-day comment period by an additional 30 days to provide industry and other interested stakeholders ample opportunity to review the proposed rule and submit comments. In that time, BSEE received over 5,000 pages of technical comments from over 170 commenters.

The Bureau is now in the process of reviewing these comments and will revise the regulations accordingly where doing so will improve the quality of the rule. While I cannot discuss those specific changes at this time because the process has not been completed, I can assure you that the Bureau has heard industry's and other stakeholders' comments loud and clear. We have heard the concerns about drilling margins, blowout preventer inspections, accumulator capacity, and real-time monitoring. We have heard the concerns about the use of prescriptive language and about the potential, unintended consequences of the rule. The Bureau must now go through the process of reviewing the technical input received and determine how the text can be revised to best serve the interests of safety, environmental protection, and resource conservation. Any changes made will be the result of the Bureau's careful consideration of comments and suggestions made by the entities that will be affected by the Rule. This is

precisely how Congress intended the rulemaking process to work when it enacted the Administrative Procedure Act. Any suggestion that industry was blind-sided by this Rule or was somehow cut out of the process is plainly false. I share your frustration that I cannot discuss the substance of our deliberations about the rule, and although I cannot yet share how we are revising the text of the rule, I would be happy to explain any changes we have made once the final rule is published.

In addition to the Well Control Rule, the Bureau is in the process of finalizing several other proposed rules: the Arctic Rule, the Production Safety Systems Rule, and the Crane Safety Rule.

The Arctic Rule revises and adds requirements for exploratory drilling operations on the Arctic Outer Continental Shelf (Beaufort Sea and Chukchi Sea Planning Areas) where the extreme environmental conditions, geographic remoteness, lack of fixed infrastructure, and sensitive marine environment require heightened safety requirements and measures that are specifically tailored to the operational and environmental challenges of the Arctic OCS. The Arctic Rule went through very much the same process of technical development and stakeholder engagement as the Well Control Rule. In developing the Arctic Rule, the Bureau conducted an extensive campaign of public meetings and other outreach activities and reviewed more than 100,000 formal comments. Such a process is absolutely essential when developing highly technical rules that affect a broad range of stakeholders like the Arctic Rule and the Well Control Rule. Indeed, the highly complex and impactful rules through which our Bureau executes our mission depends on the types of outreach in which we have engaged throughout the development of both of our latest rules.

The Bureau is also engaged in two other major rulemakings. The Production Safety Systems Rule amends and updates BSEE regulations pertaining to safety and pollution prevention systems and will bolster human safety, environmental protection, and regulatory oversight of critical equipment involved in the production of hydrocarbons. Finally, the Crane Safety Rule proposes to incorporate the latest industry standard for the design and operation of cranes mounted on offshore platforms with the goal of reducing the risk of lifting incidents – a much needed improvement in our regulations as lifting incidents involving cranes have increased

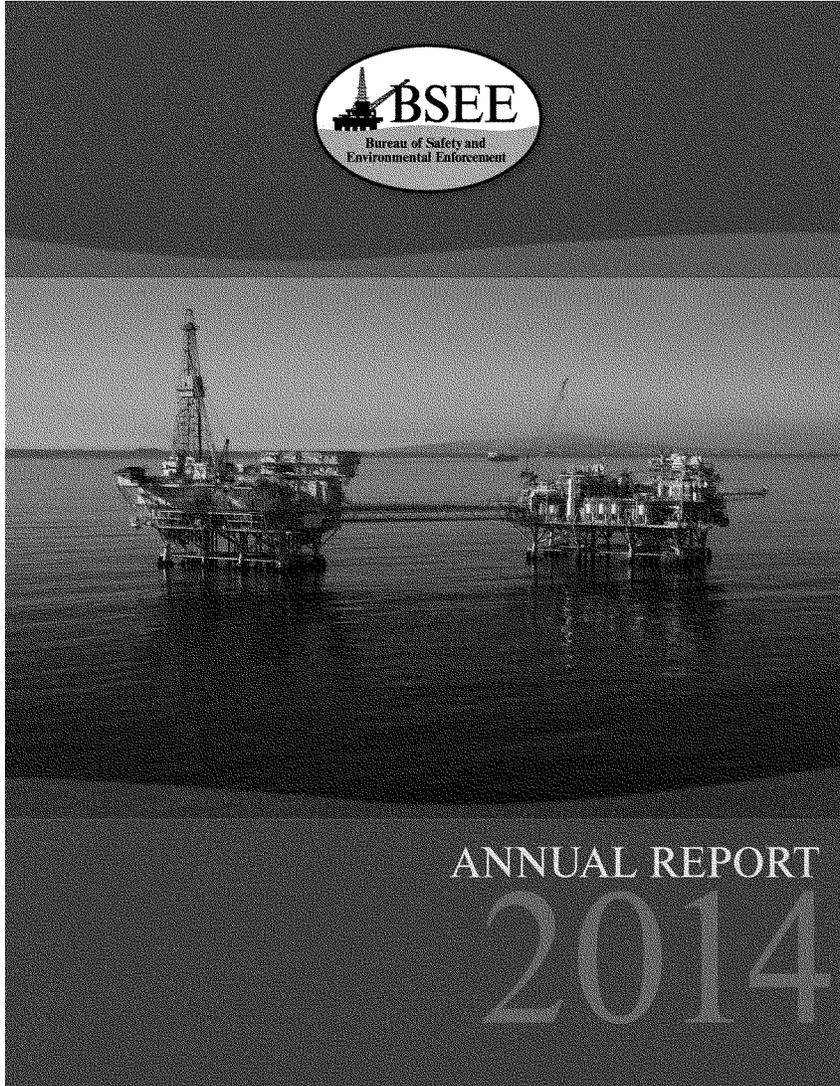
in recent years.⁷ Each of these rulemakings, in addition to the Well Control Rule, plays a critical role in advancing offshore safety and reducing the risk of fatalities, injuries, oil spills, and other offshore incidents.

Since its formation in 2011, the Bureau of Safety and Environmental Enforcement (BSEE) has focused on ensuring that companies operate offshore in a safe and environmentally responsible manner. The Well Control Rule represents a substantial step forward in line with our agency's mission to improve safety and reduce risk offshore. The Rule is the result of a confluence of investigations, studies, technology assessments, stakeholder consultations, and other activities and, once finalized and put into effect, we believe will represent the greatest improvement in offshore safety in almost three decades. It also serves as a testament to the 11 lives lost as a result of the *Deepwater Horizon* tragedy.

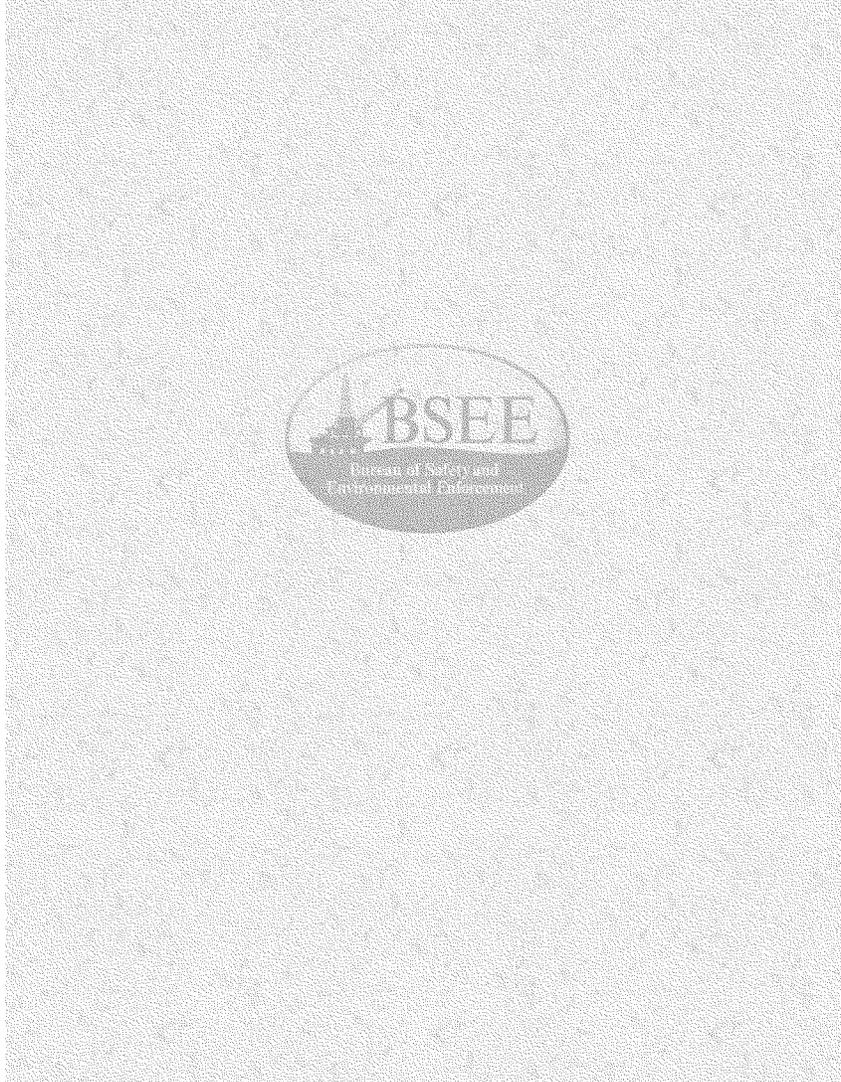
Our work as regulators – on behalf of the American people – is never finished and we must strive to keep pace with the risks of offshore drilling and production while promoting the development of a positive culture of safety amongst offshore operators. Our commitment and duty to the public is to remain vigilant in instituting the reforms necessary to achieve this goal. We believe that the Well Control Rule is one of several necessary reforms that we are undertaking that will create a safer environment offshore. We will continue to work cooperatively with the regulated community to promote best practices and to support a robust culture of safety within the offshore oil and gas industry, which produces these resources that are so valuable and essential to our economy.

This concludes my formal statement, and I am happy to answer any questions you have at this time.

⁷ See Attachment 1 at 43. Also available at http://www.bsee.gov/uploadedFiles/BSEE/BSEE_Newsroom/Publications_Library/Annual_Report/BSEE%202014%20Annual%20Report.pdf.



ANNUAL REPORT
2014



Letter from the Director



I am very pleased to present the Bureau of Safety and Environmental Enforcement (BSEE) 2014 Annual Report, the first such report produced by the bureau since its formation in 2011. This report highlights BSEE's activities in promoting safety, protection of the environment, and conservation of offshore resources. It also provides a useful summary of safety performance and environmental compliance trends on the Outer Continental Shelf (OCS), as well as BSEE's priorities going forward. Our intention is that this will be the first of many periodically produced reports focused on OCS performance.

As will be evident as you read through the report, BSEE is focused on the reduction of risk offshore. We pursue this objective through a comprehensive program of regulations, technical assessments, inspections, and incident investigations. In addition, we place great emphasis on the establishment of a safety culture throughout industry, the cornerstone of this effort being the Safety and Environmental Management System, or SEMS. SEMS is performance based, and forms a necessary counterpart to our more traditional regulatory oversight activities. We believe this hybrid approach is the most realistic way to take safety to the next level.

Part of managing risk is monitoring the trends we are seeing offshore, and gauging the effectiveness of our approach. This not only provides a valuable perspective on risks, it helps direct our future efforts. Moreover, information of this nature needs to be shared among all stakeholders, so that we have a common appreciation for the progress that has been made as well as the challenges ahead. It is in this spirit that we developed this report.

In the coming year, you can expect to see further development of many concepts presented in this report, and which BSEE has advanced during 2014. Concepts such as: risk-based inspections, near-miss reporting, a strengthened ability to assess emerging technology, and continued investment in environmental response capability. We will continue to refine the SEMS program. All of these initiatives support a culture of safety and the management of risk, and all will add to our ability to assess trends and share information.

A necessary pre-condition for continual improvement is having the necessary talent within our organization. Therefore we will maintain a long-term strategic focus on our workforce, and strive to attract the best talent our Nation has to offer. We will engage with youth, college and university students, returning veterans, and industry professionals in this effort. This will serve not only the internal interests of our Bureau, but more importantly the needs of the public and the industry, both of whom demand a highly knowledgeable and adaptable regulator. We would welcome interest from academia, industry and non-governmental organizations in this regard.

It was an exciting year at BSEE in 2014, and 2015 and beyond promise to be equally so. Please review this report and feel free to give us your feedback on how we can improve it to better suit your interests. We value our engagement with you!

Sincerely,

Brian Salerno

Director

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Overview of BSEE

Mission

The Bureau of Safety and Environmental Enforcement (BSEE) promotes safety, protects the environment, and conserves energy resources offshore through vigorous regulatory oversight and enforcement.

BSEE, a bureau within the U.S. Department of the Interior (DOI), is the United States' regulator of offshore energy exploration, production, and development. BSEE's jurisdiction and regulatory responsibilities are defined by the Outer Continental Shelf Lands Act (OCSLA), which outlines federal responsibility over the submerged lands of the Outer Continental Shelf. BSEE ensures compliance with provisions of other federal laws, including the National Environmental Policy Act, the Clean Air Act, the Clean Water Act, the Federal Oil and Gas Royalty Management Act, and Oil Pollution Act of 1990.

BSEE uses the full range of authorities, policies, and tools to compel safety, emergency preparedness, environmental responsibility, and appropriate development of offshore oil and natural gas resources.

Key functions include:

- An offshore regulatory program that develops standards and regulations, and emphasizes a culture of safety in all offshore activities;
- Oil spill prevention and preparedness including evaluation of industry oil spill response plans to ensure compliance with regulatory requirements;
- Funding scientific research to enhance the information and technology needed to build and sustain the organizational, technical, and intellectual capacity within and across BSEE's key functions that keeps pace with industry technological improvements, innovates regulation and enforcement, and reduces risk through systematic assessment and regulatory and enforcement actions in order to better carry out the BSEE mission;
- Investigations of serious incidents and allegations of unsafe and/or illegal conduct during offshore operations; and
- Enforcement of all applicable environmental and operational regulations, as well as ensuring that operators adhere to the stipulations of their approved leases, plans, and permits.



BSEE Structure

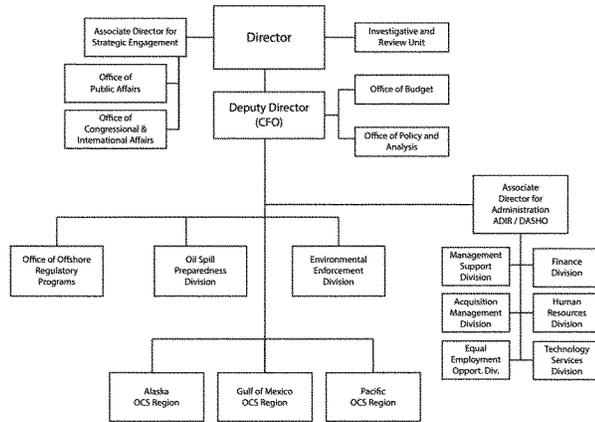


Figure 1: The organizational structure of BSEE as of December 2014.

BSEE’s mission is supported by national offices and divisions located in the Washington, D.C., metro area and three regional offices located in Anchorage, Alaska; New Orleans, Louisiana; and Camarillo, California. The regional offices review and grant permits, perform inspections, issue citations, prepare and refer civil penalties, and investigate incidents. The three headquarters-based divisions—Office of Offshore Regulatory Programs, Oil Spill Preparedness Division, and Environmental Enforcement Division—work with the regional offices to ensure that BSEE’s regulatory responsibilities are carried out effectively. The Office of Offshore Regulatory Programs develops standards and regulations to enhance operational safety and environmental protection for the exploration, production, and development of oil and natural gas on the OCS. The Oil Spill Preparedness Division develops and enforces requirements for offshore operators’ Oil Spill Response Plans, conducts research, and oversees the oil spill response exercise programs. The Environmental Enforcement Division provides sustained regulatory oversight to ensure compliance with all applicable environmental regulations, as well as lease, plan, and permit terms.

Contributing to America's Energy Needs

The resources and activity under BSEE's jurisdiction are vast. Five hundred and twenty-eight million barrels of oil and 1.3 trillion cubic feet of natural gas were produced on the OCS from January to December 2014 (Table 1). This offshore oil and gas production accounted for 16 percent of America's domestic oil production and 5 percent of gas production¹. Table 2 illustrates the diverse types of activities that occur in each of the regions.

Table 1: Production by Region in 2014.

	Alaska Region	Gulf of Mexico Region	Pacific Region	Total OCS
Oil (barrels)	603,698	509,304,746	18,439,833	528,348,277
Gas (MCF ²)	30,744,323	1,273,521,681	28,191,781	1,332,457,785

Table 2: Offshore Activity and Infrastructure on the OCS by Region in 2014.

	Alaska	Gulf of Mexico	Pacific
Designated Operators	4	133	6
Platforms	1 ³	2,481	23
Total Wells Drilled	0	329	21
Weekly Average Number of Working Drilling Rigs	0	116	14
Miles of Pipelines	0	27,267	213

The Energy Information Administration projects offshore production will continue to grow through 2040, as the pace of development activity quickens and new large development projects, predominantly in the deepwater and ultra-deepwater areas of the Gulf of Mexico (GOM), are brought into production.

BSEE approved 317 drilling permits in 2014. Before a permit to drill can be granted, however, there are many direct and related approvals, including environmental compliance that must be in place. To that end, the well may not be drilled within the same calendar year. As a result of current and past approvals, operators drilled 330 wells in 2014.

"The resources and activity under BSEE's jurisdiction are vast. Five hundred and twenty-eight million barrels of oil and 1.3 trillion cubic feet of natural gas were produced on the OCS from January to December 2014."

¹ Data percentages were derived from total domestic oil and gas production numbers listed at www.EIA.gov.

² MCF = thousands of cubic feet.

³ The Alaska Region has one producing project that consists of six producing wells on the Federal OCS from a gravel island located in Alaska State waters.

Focus Areas for BSEE in 2014

In 2014, the Bureau set organizational priorities based on focus areas outlined by Director Salerno: risk management, safety and environmental compliance, organizational effectiveness, transparency, and people. These focus areas strategically prioritize the Bureau's actions, and are strengthened by BSEE's guiding principles of clarity, consistency, predictability, and accountability to the American public and the regulated community.

Risk Management

Risk management is critical for BSEE to achieve its mission. In 2014, BSEE made progress to reduce both internal risks to the organization and external risks that the Bureau influences through its operational activities. BSEE reduced internal risks by investing in its people, increasing transparency in its decision-making processes, and implementing lessons learned from previous offshore incidents. BSEE's ability to recognize, assess, manage, and drive mitigation of external operating risks throughout all offshore activities is critical for effective inspections and permit evaluation and processing. BSEE is able to more efficiently and effectively manage its internal resources and build its capacity to take a proactive position for ensuring safe and responsible offshore energy development by applying a risk management methodology and selectively shifting BSEE oversight from assessing compliance to assessing the effectiveness of operations, technologies, and procedures.

The Bureau has undertaken a number of projects to improve risk management and reduce risk. One project is to identify the multiple physical barrier system for all the major modes of offshore operations. This means identifying the successful approach required to fulfill each major mode; to date BSEE has done this for the comparison of conventional drilling and managed pressure drilling, and for production platforms for the flow path of hydrocarbons. Hand in hand with this effort is another project to identify safety critical equipment associated with offshore operations under BSEE's oversight responsibility.

In order to reduce risk, both industry and BSEE need information that can be used to compare outcomes and identify effective mitigation strategies. BSEE helped increase information available to identify and quantify risk across the offshore industry by partnering with the Bureau of Transportation Statistics (BTS) to develop the near-miss reporting system, Safe OCS. BTS is developing the reporting system and will act as a third-party repository of the reported data when operational. The system will provide anonymity to the reporting source and impose substantial legal penalties for anyone who breaks these protections. Safe OCS has enormous potential to increase understanding of potentially severe safety problems that are averted. The aggregate data provided by this system will be publically available on the BTS website, will assist with the identification of leading indicators for incidents, and will inform prevention and mitigation efforts.

Cutting-edge offshore technologies also create risks that must be quantified and understood in order to better protect lives and the environment. BSEE invested over \$23 million⁴ to ensure that emerging technologies are thoroughly evaluated through 35 research studies⁵, strategic partnerships, and providing the start-up funds for the Ocean Energy Safety Institute⁶ (OESI). The OESI is a collaborative

⁴ During Fiscal Year 2014, extending from October 1, 2013 to September 30, 2014.

⁵ Technology Assessment Programs at BSEE: <http://www.bsee.gov/Technology-and-Research/Technology-Assessment-Programs/index/>

⁶ Ocean Energy Safety Institute at Texas A&M University: <http://oesi.tamu.edu/>

initiative involving government, academia, and scientific experts. It facilitates research and development, training federal workers on identification and verification of Best Available and Safest Technology (BAST), and implementation of operational improvements in the areas of offshore drilling safety and environmental protection, blowout containment, and oil spill response. From investing in employees and processes to building industry-wide tools, BSEE has actively worked to reduce both internal and external risks throughout 2014.

Safety and Environmental Compliance

BSEE continued to promote a robust safety culture and environmental stewardship across the offshore industry in 2014 through its various compliance and research tools.

The Safety and Environmental Management Systems (SEMS) program is an important element in these efforts, and forms the cornerstone of a hybrid regulatory approach that emphasizes performance in order to achieve risk reduction offshore. This year, BSEE analyzed the first round of SEMS audits concluded in 2013. BSEE found that system maturity and the level of SEMS awareness and understanding varied significantly among operators. BSEE will continue to work with industry stakeholders on meeting their SEMS requirements, to ensure that companies working offshore create a safety culture that enables operations over and above regulatory compliance. BSEE also will continue to train its own inspectors to look for evidence of a robust safety culture and to evaluate how well the workforce adheres to an operator's SEMS when they conduct their annual inspections.

BSEE continues to verify environmental compliance of permits in order to protect the marine environment. BSEE continued to engage our international regulatory counterparts to share lessons learned, enhance pollution prevention, and coordinate preparations for potential oil spill responses. By engaging U.S. neighbors and other key international partners, BSEE is reducing risks to the shared marine environment, and promoting safety and environmental stewardship that extends beyond international boundaries.

Ensuring that appropriate technologies exist to respond to an oil spill is critical for mitigating environmental risks. BSEE invested nearly \$14 million in 30 new projects in Fiscal Year 2014⁷ to develop and assess oil spill mitigation options.⁸ Studies funded by BSEE evaluated the feasibility of response strategies in the Arctic, dispersant efficacy, and remote sensing options that may be used to track oil after a spill. The National Academy of Sciences vetted a BSEE-funded research study⁹ that revised the method and variables that are evaluated in determining whether appropriate capabilities are available to respond to an offshore oil spill. BSEE began to implement these results as practical tools that could support future planning requirements. BSEE continued to manage Ohmsett¹⁰, which is the premiere facility for testing, research, and training for oil spill responses. It is the only U.S. facility where full-scale oil spill response equipment can be used in a safe, controlled, and contained simulated marine condition. Using the Ohmsett facility, BSEE researchers conducted six weeks of critical training for oil

⁷ Fiscal Year 2014 extended from October 1, 2013, to September 30, 2014.

⁸ Oil Spill Response Research at BSEE: <http://www.bsee.gov/Technology-and-Research/Oil-Spill-Response-Research/index/>

⁹ A description of the research can be found at: <http://www.bsee.gov/Technology-and-Research/Oil-Spill-Response-Research/Projects/Project-673/>

¹⁰ More information concerning Ohmsett can be found at: <http://www.ohmsett.com/>

spill response personnel and a large-scale independent testing of dispersant effectiveness under cold water conditions. Through its oil spill response research, BSEE is working to reduce the risk that potential spills could pose to the marine environment.

Organizational Effectiveness

Over the course of 2014, staff across BSEE contributed to planning strategic program realignments that will help BSEE reduce risk inherent to our internal processes and increase the Bureau's ability to mitigate external risk across the OCS. These realignments focus on a national program model for core functions such as technology, investigations, enforcement, environmental compliance, and data stewardship. This approach will increase coordination and consistency across BSEE regions, and help BSEE enhance safety and environmental stewardship across the OCS. Planning was completed in 2014, and the national program model will be implemented in 2015.

BSEE, recognizing the need to evolve with a dynamic industry, bolstered its technological capacity by establishing the Engineering Technology Assessment Center (ETAC) in Houston. The center, when fully staffed, will serve as a focal point for emerging technology evaluation and provide additional capability for BSEE to enhance its current technology assessment functions. The technology center will leverage BSEE's internal expertise with contract support, while providing a primary point of interaction with the Ocean Energy Safety Institute on technology projects. ETAC will work with industry to increase technologically-focused research and development that could lead to improved technologies that reduce risk across all operations offshore.



Ensuring Transparency

BSEE undertakes its mission on behalf of the American public. The Bureau is committed to ensuring that its decisions and actions are driven by data, and are transparent to the public we serve. As such, we must enhance our use of data and make that data readily available to the public, while protecting privacy, proprietary, and business confidential information. To meet these important objectives, BSEE has placed a significant focus on creating a Data Stewardship team, whose primary responsibility is to focus on improving the overall quality and use of our data. Additionally, we are working to ensure the availability of the necessary tools for effective data management and use of data. In 2014, BSEE completed a Business Intelligence pilot to prove the viability of such a tool in our current technology architecture. The pilot was highly successful in demonstrating how we could better use data, and the Bureau is now working to deploy the pilot across the Bureau.

BSEE is refining its definition of enforcement and clarifying the objectives of its enforcement function. It also is developing transparent policies for when and how to administer various enforcement tools, which may increase the impact of enforcement on risky industry behaviors. An effective compliance program requires clear and understandable standards, sufficient reporting and recordkeeping to measure compliance, an effective oversight program in the field, a range of enforcement tools graduated to risk, and incentives to move beyond baseline compliance to an effective safety and environmental protection management system.

To achieve greater accountability within the federal framework, the Bureau has undertaken a series of agreements with other federal partners over the past several years. BSEE and the U.S. Coast Guard recognize the importance of consistency for ensuring transparent regulation offshore. In 2014, the two agencies, who share regulatory jurisdiction on the OCS, signed a Memorandum of Agreement (MOA) in 2014.¹¹ The MOA clearly outlines the responsibilities of each agency for inspection and oversight of systems and sub-systems for fixed facilities on the OCS. This memorandum will ensure a comprehensive joint approach in the regulation of these facilities, and offer transparent and consistent expectations to all OCS stakeholders.



“BSEE undertakes its mission on behalf of the American public. The Bureau is committed to ensuring that its decisions and actions are driven by data, and are transparent to the public we serve.”

¹¹MOA between BSEE and the USCG:

http://www.bsee.gov/uploadedFiles/BSEE/International_and_Interagency_Collaboration/Interagency/Agreements/MOA-2014-USCG-Fixed%20OCS%20Facilities.pdf

People

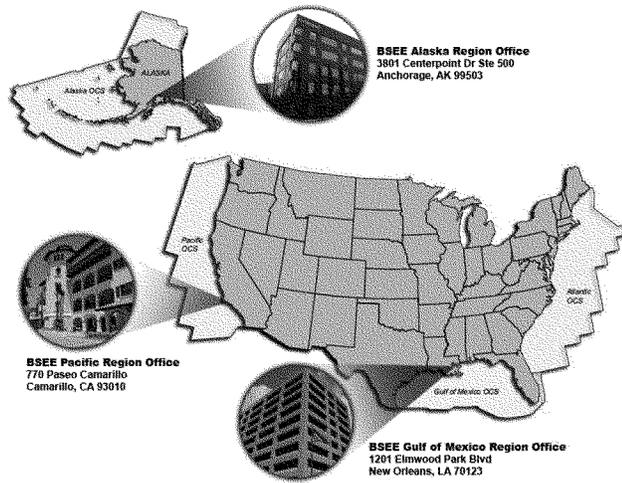
BSEE is taking steps to meet the consistent challenge of recruiting and retaining top talent. BSEE offers comprehensive technical training, and provides advancement opportunities for employees to become leaders in their fields. In 2014, BSEE initiated a Bureau-wide program that fosters a more inclusive work environment and encourages employees to embrace the value of diversity. Additionally, BSEE continues to offer special higher salary rates for grades GS-5 through GS-15 for Petroleum Engineers, Geologists, and Geophysicists within the BSEE Gulf of Mexico Region to more effectively compete with industry for talent. Despite inherent challenges, BSEE was successful in 2014 recruitment efforts. The Bureau hired 88 personnel, a net gain of nine full time equivalent employees, of which 56 were from critical scientific, inspection, and engineering fields. BSEE continues to implement a nationwide targeted campaign to aggressively recruit from university and professional job fairs. BSEE participates in the Department of the Interior's Youth Initiative and has helped to bring "The offshore" to classrooms in 2014. Moving forward, BSEE will remain committed to hiring, retaining, and fostering the next generation of a highly skilled, qualified, and diverse workforce dedicated to accomplishing BSEE's mission.

The Bureau is committed to employee development, as well as retention of a highly technical workforce. BSEE staff leveraged in-house training and external training opportunities held by third parties, including academia, other federal agencies, and industry. We make our training classes available to other federal agencies and, in certain circumstances, other international regulators. In calendar year 2014, BSEE offered 105 training courses with 24,486 contact training hours conducted. One hundred forty five engineers attended an average of three classes each, while 124 inspectors attended an average of approximately four classes each. Additionally, 16 members of the United States Coast Guard (USCG) and three foreign nationals participated.



Report from the Regions

BSEE's three regional offices are: the Gulf of Mexico Region (New Orleans, Louisiana); the Alaska Region (Anchorage, Alaska); and The Pacific (Camarillo, California). Each BSEE region has a common mission and similar responsibilities; however, each Region is charged with oversight of oil and gas operations that present unique challenges and circumstances. The Gulf of Mexico Region has the most extensive exploratory and production activities on the OCS and, as such, involves oversight of a broad range of upstream oil and gas activities. The Pacific Region has not had any new exploration activities in years, yet it continues to have responsibility over a variety of different types of production facilities. In particular, The Pacific staff specialize in the maintenance of maturing assets and the conservation of reservoir resources. The Alaska Region is BSEE's youngest region, in terms of the stage of exploration and development activities occurring or proposed to occur. The oversight of these frontier operations is critically important as companies explore and plan to develop oil and gas resources in the Alaska OCS.



Gulf of Mexico

The majority of exploration, production, and development activities occur in the Gulf of Mexico Region. BSEE's Gulf of Mexico Region faces increasing levels of activity, with deeper wells at higher pressures and temperatures in both shallow and deepwater.

During 2014, activity in the Region remained robust, despite the turbulence in the oil and gas markets. There was an increase in deepwater floating drilling rig activity from 40 (19 drill ships and 21 semisubmersibles) in 2013 to 52 (33 drill ships and 19 semisubmersibles) in 2014. In addition, six new drill ships are expected to start work in the Gulf of Mexico in 2015. The number of deepwater floating production facilities in the Region also increased with the installation of two production spars and two semisubmersible facilities. These new facilities (and associated pipeline infrastructure) have required increased inspection and oversight to ensure the protection of personnel and the environment. BSEE's Gulf of Mexico Region oversight responsibilities include a readiness to deploy teams of inspectors and investigators in response to offshore incidents. During 2014, Region personnel, along with personnel from BSEE's Investigations and Review Unit, investigated a number of offshore incidents, including a gas blowout and an explosion resulting in a fatality. Incidents resulting in environmental harm and injuries to personnel also were investigated. The Region reviews and assesses new technologies and the innovative use of existing technology when projects are still in the concept design phase. To do this, the Region coordinates with headquarter program managers to ensure that BSEE is positioned to effectively and efficiently assess the proposed use of new technologies and operations to identify any risks to offshore personnel and the environment. During 2014, the Region supported Bureau-wide initiatives to engage international regulators and market participants to share information on risks and common safety and environmental protection priorities. This included meetings with regulators from Denmark, Norway, and the United Kingdom, as well as international oil and gas operators and contractors on specific areas of mutual interest including risks associated with shallow water operations.



“BSEE’s Gulf of Mexico Region faces increasing levels of activity, with deeper wells at higher pressures and temperatures in both shallow and deepwater.”

BSEE's Gulf of Mexico Region also continued in 2014 its efforts to engage the next generation of offshore scientists, engineers, and investigators by participating in a number of STEM-related events. In late 2014, the Region hosted seniors from a local high school and taught them about BSEE's mission to ensure safe and responsible offshore operations.



Pacific

The BSEE Pacific Region has mature fields and aging infrastructure that are located in close proximity to sensitive marine environments and the coastline. As facilities age and primary production declines, BSEE's Pacific Region performs increased oversight and focuses on resource conservation. In 2014, the Pacific Region took steps to prepare for aging facility operations and eventual decommissioning. The Pacific Region enhanced its incident investigation program and implemented a preventative program that directly addresses the root causes of recurring incidents. The lessons learned from investigations in the Pacific Region were used to inform issuance of two safety alerts in 2014.¹² By initiating studies that augment the investigations process, and enhancing communications to both the public and industry, the Pacific Region worked to balance the concerns of the California community with the responsible development of offshore resources.



¹² Safety alerts for all regions can be found at <http://www.bsee.gov/Regulations-and-Guidance/Safety-Alerts/Safety-Alerts/>

Alaska

Alaska is a place of intrinsic natural resource value that also contains relatively unexplored Arctic energy potential. Although no drilling or exploration activities were pursued on the Alaska OCS in 2014, several companies have expressed a commitment to develop their leases in the years ahead. Exploratory drilling activities are expected to resume in the Chukchi Sea in 2015. The key challenges faced by BSEE's Alaska region include ensuring that region-specific guidance is in place to help protect the Arctic environment in the face of extreme climatic and logistical challenges. From seasonal ice coverage and floating ice to subsistence whale hunts, the challenges posed in the Arctic are unique. Since the Alaskan Native communities are closely connected to the Arctic environment culturally, socially, and economically, BSEE's Alaska Region hired a tribal and community liaison in 2014 to facilitate the harmonization of offshore exploration with the needs of Alaskan communities, should Alaska OCS resources be developed in the future.

With international operations advancing in Arctic areas due to changing Arctic conditions, BSEE developed important relationships with fellow Arctic offshore regulators. BSEE provided critical support to working groups organized under the Arctic Council, and co-headed the U.S. delegation to the Task Force on Oil Pollution Prevention throughout 2014. BSEE was instrumental in facilitating the initiation of an Arctic Offshore Regulators Forum (AORF). The AORF will be a technical and operational forum for offshore petroleum safety regulators to exchange information, best practices, and relevant experiences that are unique to the Arctic, in order to continually improve offshore safety and environmental protection. BSEE represents the U.S. as the inaugural chair for the AORF management committee and has worked to establish the organization's Terms of Reference and initial work sessions for that organization.



Regulatory Activity in 2014

Regulatory refinements and/or enforcements are a primary approach that BSEE uses to reduce risk to offshore workers and the environment. In 2014, BSEE continued to finalize the Production System Safety Rule¹³ which refines the requirements of 30 CFR § 250 Subpart H. The Bureau released proposed rules for publication for Arctic Operations,¹⁴ as well as a comprehensive well control rule that incorporates many technical recommendations made following the *Deepwater Horizon* tragedy. BSEE also published an Advanced Notice of Proposed Rulemaking¹⁵ to solicit feedback from the public and regulated community on helicopter and aviation safety on fixed offshore structures, recognizing that the majority of offshore fatalities for offshore workers occurred during transportation incidents. In 2014, BSEE conducted over 4,800 facility inspections (facilities can include rigs, platforms, pipelines or on-shore meters) at approximately 2,500 facilities, and issued approximately 2,900 INCs. BSEE collected \$5,695,498 million in 53 civil penalty cases. BSEE staff completed 95 formal incident investigations.¹⁶ BSEE also began developing a risk-based inspection methodology to target areas of the greatest risk. A pilot project will begin in 2015 that will focus on past performance, Safety and Environmental Management Systems Compliance, and other conditions.

During 2014, BSEE used a variety of enforcement tools to respond to violations and to promote compliance. To avoid potential harm to personnel and the environment, BSEE issued 153 facility shut-in Incidents of Non-Compliance (INCs) and 1,146 component shut-in INCs.¹⁷ In 2014, BSEE referred 58 violations for civil penalty assessment, with eight related to contractors. The number of referred civil penalty cases has been steadily increasing since 2012, with 38 referrals in 2012 and 56 cases referred in 2013. BSEE also met with 57 operators during 2014 to review annual performance and to recommend specific performance improvement measures. BSEE continued to oversee improvements by one operator through a performance-improvement-plan, which BSEE required after the operator was involved in repeated incidents during OCS operations.

BSEE is currently implementing measures that will ensure that it is prepared to utilize the full range of regulatory and administrative enforcement tools in the coming years. These efforts are aimed at continued improvement of the Bureau's ability to promote safe and environmentally responsible offshore operations.

“BSEE is currently implementing measures that will ensure that it is prepared to utilize the full range of regulatory and administrative enforcement tools in the coming years. These efforts are aimed at continued improvement of the Bureau's ability to promote safe and environmentally responsible offshore operations.”

¹³ <http://www.gpo.gov/fdsys/pkg/FR-2013-08-22/pdf/2013-19861.pdf>

¹⁴ http://www.bsee.gov/uploadedFiles/BSEE/Regulations_and_Guidance/Proposed_Rules/ArcticNPRMFRnotice.2.24.15.pdf

¹⁵ <http://www.regulations.gov/#!docketDetail;D=BSEE-2014-0001>

¹⁶ See <http://www.bsee.gov/Inspection-and-Enforcement/Accidents-and-Incidents/Incident-Investigations/>

¹⁷ Component shut-in INCs are issued for a portion of the facility that is to be shut-in until corrective action is completed.

Inspections

Table 3: Inspections performed by BSEE on the OCS by region from January 1, 2014, to December 31, 2014. Note that inspection types are not mutually exclusive, and several functions may be examined during the same inspection.

Type of Inspection	BSEE Total	Alaska	Gulf of Mexico	Pacific
Well Operations ¹⁸	1,249	0	1,147	102
Production ¹⁹	3,226	2	3,006	218
Pipelines ²⁰	4,241	0	4,189	52
Meters ²¹	4,374	2	4,357	15
Environmental ²²	3,263	2	3,073	188
Other ²³	4,033	0	3,773	260
Total	20,386	6	19,545	835

¹⁸ Well operations inspections include: drilling, workover, completion, and abandonment.

¹⁹ Production inspections include production and flaring.

²⁰ Pipeline inspections involve the review of service and maintenance records and checking safety valves and devices.

²¹ Meters inspections involve the review of calibration documents and the physical inspection of seals.

²² Environmental inspections include: pollution, air quality, and oil spill exercise.

²³ Other includes USCG guidelines, hydrogen sulfide, site security, and compliance inspections.

Oil Spill Preparedness Verification Audits and Exercises

Table 4: Oil spill preparedness verification and audits conducted in each region during calendar year 2014.

	Total OCS	Alaska Region	Gulf of Mexico Region	Pacific Region
Table Top GIUE ²⁴	9	0	7	2
Deployment GIUE	3	0	2	1
Spill Management Team Audits	55	2	46	7
Equipment Deployment Audits	24	0	22	2
Equipment Verification of Capabilities	41	0	39	2
Total	132	2	116	14

²⁴ GIUE is a Government Initiated Unannounced Exercise. BSEE has the authority to initiate GIUEs under 30 CFR § 254.42(g)

Incidents of Non-Compliance (INCs)

Table 5: INCs issued by region and category from January 1, 2014, to December 31, 2014. The data in the table does not include rescinded INCs.

INC Category	BSEE Total	Alaska	Gulf of Mexico	Pacific
Completion	16	0	16	0
Crane	64	0	54	10
Drilling	104	0	102	2
Electrical	160	0	105	55
General	933	0	869	64
Hydrogen Sulfide	5	0	4	1
Measurement & Site Security	488	0	488	0
Pipelines	62	0	60	2
Pollution	147	0	141	6
Production	762	0	678	84
Well Work-over/Abandonment	48	0	48	0
USCG-related	114	0	103	11
Total	2903	0	2668	235

Civil Penalties

Table 6: Top ten companies paying the most in civil penalties for violations on the OCS in 2014 are shown in the table below. Over \$5 million was collected from 53 cases from January 1, 2014, to December 31, 2014. All revenues collected as part of the civil penalties program are collected and distributed by the U.S. Department of the Treasury.

Violating Company	Total Fines Paid	Number of Cases
GOM Shelf LLC	\$1,230,000	1
Apache Corporation	\$475,000	3
EnVen Energy Ventures, LLC	\$438,000	1
Black Elk Energy Offshore Operations, LLC	\$355,000	4
Mariner Energy Resources, Inc.	\$295,000	1
Mariner Energy, Inc.	\$280,000	1
SandRidge Energy	\$250,000	1
Chevron U.S.A. Inc.	\$220,000	3
Linder Oil Company	\$175,000	2
Dynamic Offshore Resources, LLC	\$170,000	2
Total OCS Civil Penalties	\$5,695,498	53

Safety Performance on the OCS

Operators on the OCS are required to report incidents related to operations associated with permits, leases, and other activities regulated by BSEE (30 CFR § 250.187-190). Incidents that must be reported include fatalities, injuries requiring evacuation of the injured person, losses of well control, fires and explosions, incidents that result in structural damage, gas releases that initiate equipment or process shutdown, reportable²⁵ releases of hydrogen sulfide (H₂S) gas, collisions resulting in property or equipment damages greater than \$25,000, incidents involving crane or personnel/material handling operations, incidents that damage or disable safety systems or equipment, spills of a barrel or more,²⁶ musters for evacuation for reasons not related to weather or drills, and all other incidents resulting in property or equipment damage greater than \$25,000. (30 CFR § 250.188). BSEE investigates these incidents and uses the findings to identify incident causes and trends. This information helps BSEE identify appropriate actions to prevent the recurrence of incidents and enhance safety and environmental protection on the OCS. Incident data is reported below from calendar year 2007 to 2014, after the publication of the Incident Reporting Rule²⁷ that became effective July 17, 2006. The Incident Reporting Rule more clearly defines which incidents must be reported, broadens the scope to include incidents that have the potential to be serious, and requires the reporting of standard information for both oral and written reports. This has resulted in more consistent incident reporting and the collection of more reliable incident information.



“BSEE investigates these incidents and uses the findings to identify incident causes and trends. This information helps BSEE identify appropriate actions to prevent the recurrence of incidents and enhance safety and environmental protection on the OCS.”

This safety information is reported here to provide a high-level overview of safety performance on the OCS, and identify trends and emerging safety and environmental performance concerns. By identifying areas for improvement, both BSEE and industry can move towards addressing emerging concerns and reduce risk on the OCS. In the data that is shown in the figures of this document, please note that the numbers for 2010 to 2011 were impacted due to a lack of drilling after the *Deepwater Horizon* tragedy occurred.

²⁵ Reportable releases are defined in 30 CFR § 250.490(i).

²⁶ Reporting required by 30 CFR § 250.187 in accordance with 30 CFR § 254.46.

²⁷ 30 CFR § 250.187-190.

Table 7: Total number of incidents occurring on the OCS for years 2007 to 2014.

Incident	2007	2008	2009	2010	2011	2012	2013	2014
Fatalities ²⁸	5	11	4	12	3	4	3	1
Injuries	440	332	301	285	231	287	268	277
Loss of Well Control	7	8	6	4	3	4	8	7
Fires/Explosions	118	151	145	130	105	140	111	121
Collisions	21	22	29	8	14	10	23	12
Spills (> 50 bbls)	4	33	11	5	3	8	6	8
Lifting	161	201	222	101	109	179	197	206
Releases (Gas or H ₂ S)	18	28	25	19	20	19	22	29
Musters for evacuation	26	48	53	28	36	49	67	51
Total	800	834	796	592	524	700	705	712

²⁸ Fatalities resulting from OCS operations.

Fatalities

Both BSEE and industry strive for a fatality-free year, every year. As such, the Bureau requires that all fatalities must be reported by immediate oral report, per 30 CFR §250.188(a)(1). An average of five fatalities resulting from operations per year occurred on the OCS between 2007 and 2014. The *Deepwater Horizon* tragedy accounted for 11 of 12 fatalities in 2010, marking the highest number of fatalities for a given year. The lowest number of fatalities for any year was in 2014, when 1 fatality was reported (Figure 2). In the past three years, there has been an overall decrease in fatalities.

The events resulting in fatalities vary, from explosions and fires to electrocutions (Figure 3). Explosions and fires were associated with 44% of fatalities on the OCS from 2007 to 2014. The *Deepwater Horizon* tragedy in 2010 was the causal factor for 11 of the 12 fatalities that year. The second most prevalent incident associated with fatalities is lifting incidents, which accounted for 16% of all fatalities from 2007 to 2014.

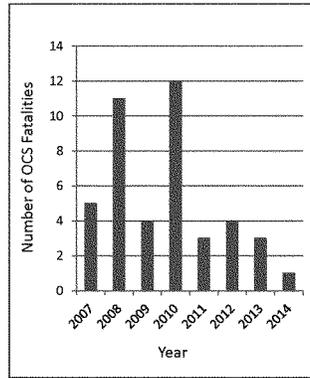


Figure 2: Number of OCS Fatalities per year.

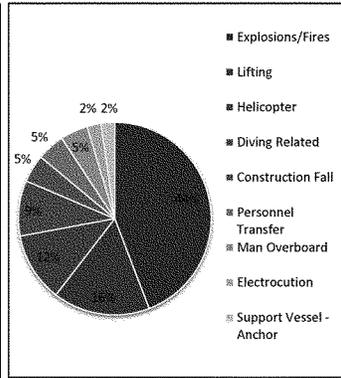


Figure 3: Causes of Fatalities for the time interval of 2007 – 2014.

Injuries

The Bureau requires the reporting of all injuries that require evacuation of the individual from the facility to shore or to another offshore facility. BSEE categorizes injuries as follows:

- Major – injuries that resulted in more than 3 days away from work, restricted duty, or transfer of the injured person to another job (DART)
- Minor – injuries that resulted in 1-3 days DART; or,
- Other – injuries that required evacuation to shore or to another offshore facility for medical treatment but did not result in any DART.

Between 2007 and 2014, an average of 303 injuries per year was reported on the OCS (Table 7). While injury incidents have generally decreased since 2007, there was a slight increase in injuries reported between 2013 and 2014 (Figure 4).

A similar decreasing trend in injuries was observed when injuries were normalized to the number of man-hours worked per year.²⁹ In 2014, 11 injuries were reported per 200,000 man-hours (Figure 5). Thirty-nine percent of injury incidents investigated by BSEE in 2013 and 2014 were caused by human engineering problems, which includes issues associated with the human-machine interface, poor working environments, system complexity, and non-fault tolerant systems. Thirty-two percent of injury incidents investigated in 2013 and 2014 were caused by problems in work direction, which is related to the planning, site preparation, selection of workers, and supervision for a specific job or task. In recent years the number of “major” injuries has declined somewhat, while the number of “minor” and “other” injuries has increased slightly (Figure 6). Overall, injuries increased slightly from 2013 to 2014. Approximately 47% of injuries reported on the OCS between 2007 and 2014 resulted in DART for more than 3 days (Figure 7).

²⁹ From 1997-2012, the number of man-hours worked and other information was reported annually by operators to BSEE through voluntary participation in the OCS Performance Measures Program (<http://www.bsee.gov/Regulations-and-Guidance/Safety-and-Environmental-Management-Systems---SEMS/OCS-Performance-Measures/>). On October 15, 2010, the Safety and Environmental Management (SEMS) Rule made the reporting of this information a requirement (30 CFR §250.1929). For this report, the number of man-hours worked for CY 2013-2014 is the total man-hours worked reported by all OCS operators. For previous years, the total OCS man-hours worked was estimated, based on the percentage of operators who reported this information.

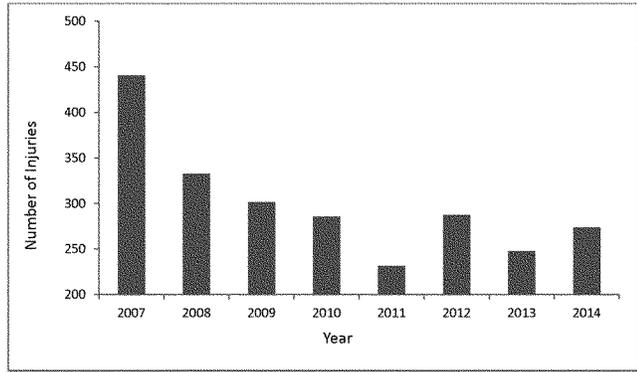


Figure 4: Number of injuries per year on the OCS for years 2007 to 2014.

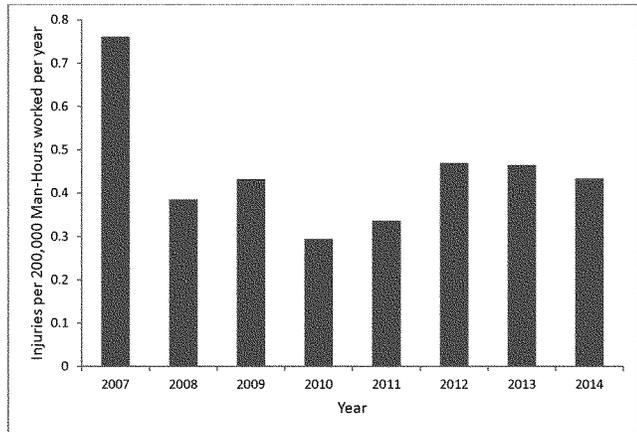


Figure 5: Injuries that occurred on the OCS normalized by man-hours for years 2007 to 2014.

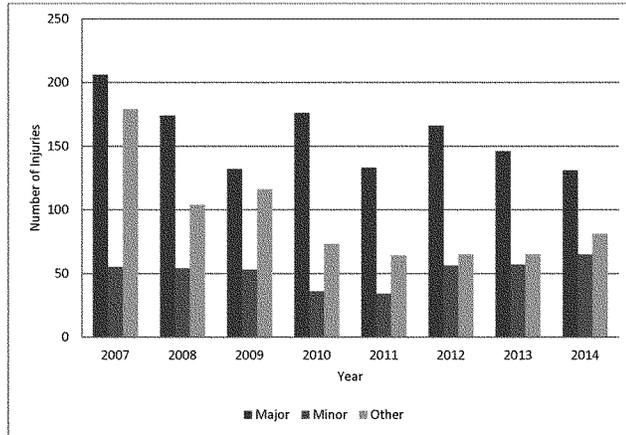


Figure 6: Injuries by category on the OCS for years 2007 to 2014.

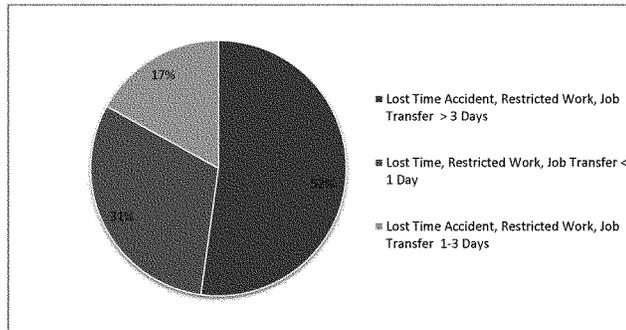


Figure 7: Injuries that occurred on the OCS for years 2007 to 2014. The color coding is based on the number of DART days; blue for major, yellow for minor, and orange for other.

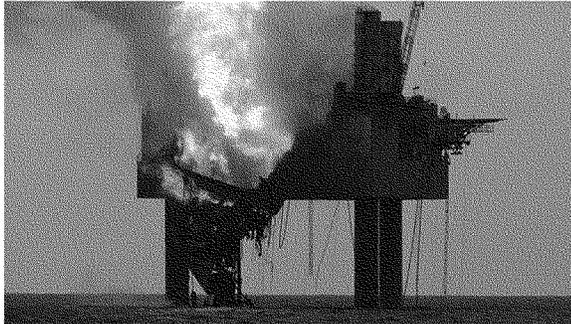
Loss of Well Control

The Bureau requires that all loss of well control incidents (LWC) be reported immediately per 30 CFR §250.188(a)(3). Loss of well control incidents are categorized into the following types:

- 1) Uncontrolled flow of formation or other fluids to an exposed formation (underground blowout);
- 2) Uncontrolled flow of formation or other fluids at the surface (surface blowout);
- 3) Flow through a diverter; or,
- 4) Uncontrolled flow resulting from a failure of surface equipment or procedures.

From 2007 to 2014, an average of six LWC incidents were reported on the OCS per year. The fewest LWC incidents were reported in 2011, and the most incidents were reported in 2008 and in 2013 when eight incidents were reported. The LWC incidents per well-related activity have increased since 2011. In 2014, the calculated rate was one LWC incident per 213 well-related activities. Six of the last seven investigations completed by BSEE for LWC incidents found that the root cause of the incidents was tied to equipment difficulties, in particular the design specifications of wells.

From 2007 to 2014, 45 percent of LWC incidents were associated with flow at the surface, 36 percent were associated with the failure of surface equipment, 11 percent were associated with flow through a diverter, and 8 percent were associated with flow underground (Figure 8). Losses of well control associated with flow at the surface most often occur during the drilling of a well or other well work operations (completion, workover, or abandonment), while losses of well control associated with underground flow and flow through a diverter occur during drilling operations. Loss of well control incidents associated with failures of surface equipment or procedures can occur during drilling, other well work, or production operations.



"From 2007 to 2014, an average of six LWC incidents were reported on the OCS per year."

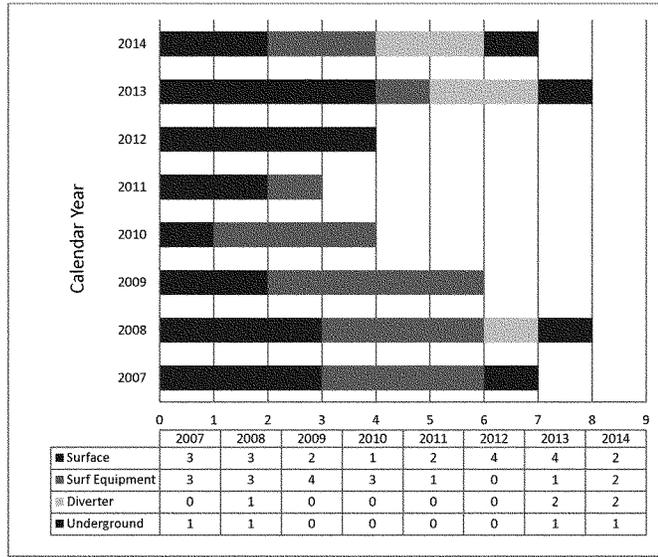


Figure 8: Losses of well control (horizontal axis) on the OCS by type, displayed by year from 2007 to 2014.

Fires and Explosions

The Bureau requires that fires and explosions lasting longer than five minutes be reported by immediate oral report, per 30 CFR §250.188(a)(4). For fires lasting less than five minutes, the Bureau requires that reporting occur within 12 hours of incident. There are four general categories of fires and explosions:

- Incidental where less than \$25,000 property or equipment damage occurs,
- Minor where \$25,000 to \$1,000,000 property or equipment damage occurs,
- Major where over \$1,000,000 property or equipment damage occurs, or
- Catastrophic where over \$10,000,000 property or equipment damage occurs with destruction of a facility.

Over the eight-year timeframe of this report, an average of 128 fires and explosions per year were reported on the OCS. The lowest number of fires and explosions, 105, was reported in 2011, and the highest number, 151, was reported in 2008 (Table 7, Figure 9). When normalized, fires and explosions per installation show an overall increasing trend (Figure 10) in the past two years. In 2014, the calculated rate was one fire or explosion per 22 installations.

In 2014, 97.5 percent of fires and explosions reported were incidental and 2.6 percent reported were minor. Throughout the analyzed 8-year period, 95.8 percent of all fire and explosion incidents were incidental, 3.7 percent were minor, 0.4 percent were major, and 0.1 percent were catastrophic (Figure 11).

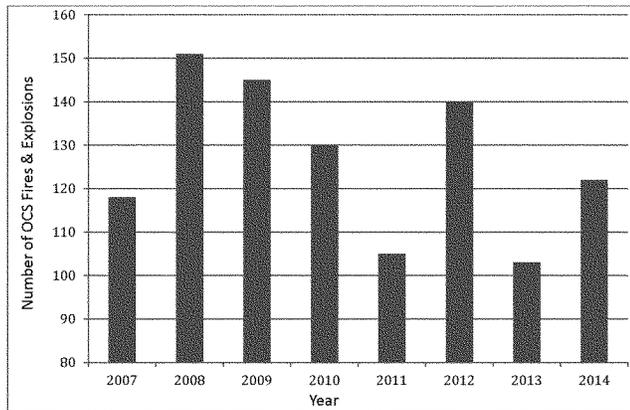


Figure 9. Fires and explosions that occurred on the OCS displayed by year for 2007 to 2014.

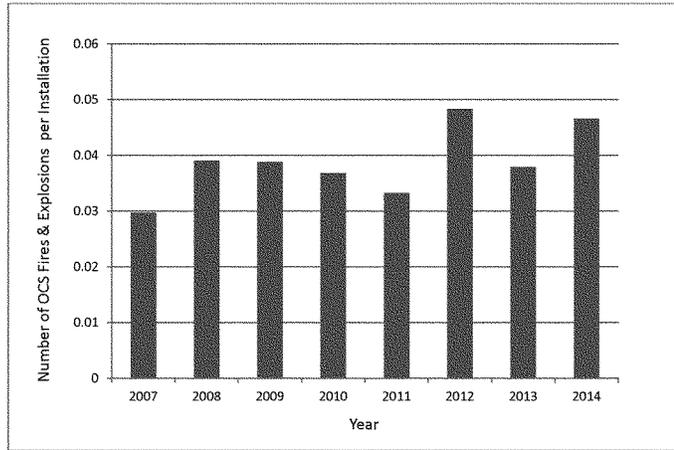


Figure 10: Total number of fires and explosions that occurred on the OCS per installation per year for 2007 to 2014.

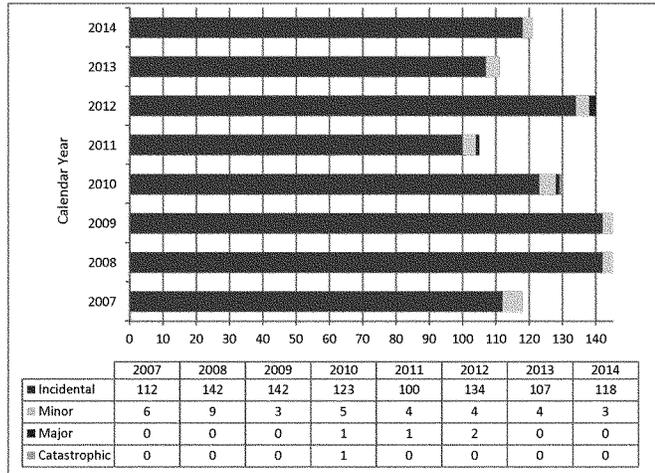


Figure 11: Fires and explosions on the OCS (horizontal axis) per category and year from 2007 to 2014.

Collisions

The Bureau requires that collisions resulting in more than \$25,000 in damage be reported within 12 hours of occurrence, per 30 CFR §250.188(a)(6). Over the 8-year timeframe of this report, an average of 17 collisions was reported per year (Figure 12). The fewest collisions were reported in 2010, and the highest number of incidents was reported in 2009. When the number of collisions is normalized to the number of installations, the highest number of collisions per offshore installation occurred in 2013. The number of collisions decreased per installation in 2014, when the calculated rate was one collision per 219 installations (Figure 13). Figure 14 depicts the breakout of major (greater than \$25,000 damage) and minor (less than \$25,000 damage) collisions. Major collisions have been declining since 2011.

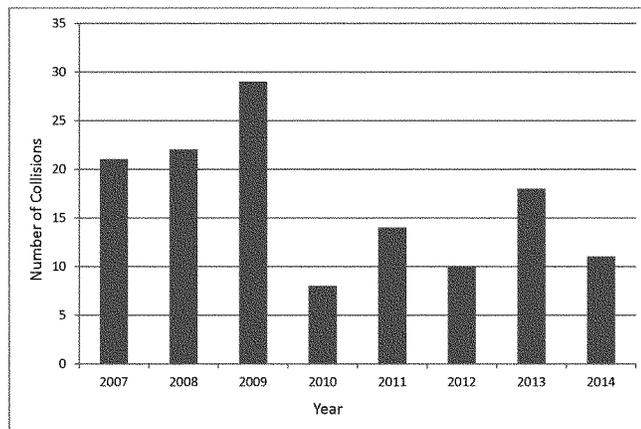


Figure 12: Number of collisions on the OCS shown annually for years 2007 to 2014.

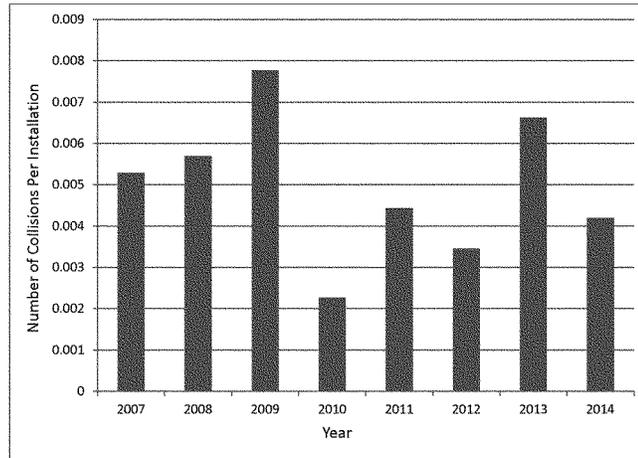


Figure 13. Collisions on the OCS installations³⁰ shown annually per installation for years 2007 to 2014.

³⁰ Installations include both production facilities (platforms) and drilling rigs.

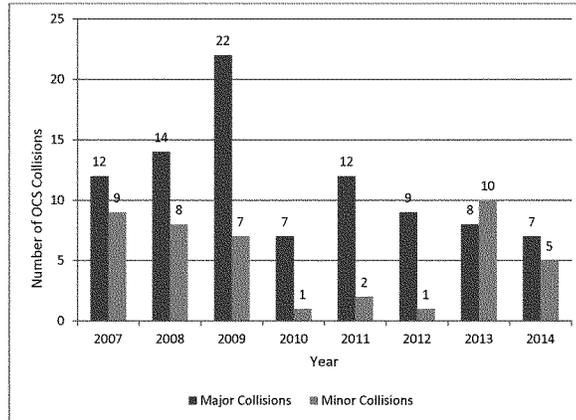


Figure 14: Collisions on the OCS depicted annually for the years 2007 to 2014. Major collisions (dark blue) correspond to property or equipment damage greater than \$25,000. Minor collisions (light blue) correspond to property or equipment damage less than \$25,000.

Spills

The Bureau requires that all pollution incidents resulting in the release of one barrel total fluid volume³¹ or more be reported by oral report immediately, per 30 CFR § 254.46(b). From 2007 to 2014, an average of ten oil spills releasing more than 50 barrels was reported on the OCS per year. The fewest number of these spills was reported in 2010, and the greatest number was reported in 2008³² (Figure 15). From 2007 to 2014, 33 percent of spills greater than 50 barrels contained crude or refined petroleum, 28 percent contained synthetic-based drilling fluid, 20 percent contained other chemicals, and 18 percent were mixtures of products resulting from topside equipment and hurricane-induced failures (Figure 16). In general, there is no real trend in the types of fluids spilled each year, though Figure 16 depicts the breakout of fluids by type and synthetic-based mud releases have increased slightly in the past several years. The number of spills was low for 2010 and 2011 due to the temporary moratorium on drilling related to post-*Deepwater Horizon* oil spill containment requirements, though the spill volume was highest for 2010 due to the *Deepwater Horizon* tragedy.

In Figure 17, the rate of the volume of petroleum spilled per volume of oil produced on the OCS is depicted. The volume of petroleum spilled includes all crude oil and refined petroleum products for spills greater than or equal to one barrel. The high rate in 2008 is due to spills associated with OCS facilities damaged during Hurricanes Gustave and Ike in the Gulf of Mexico. The large volume in 2010 is due to *Deepwater Horizon*.

In Figure 18, the number of barrels of oil produced and the number of barrels of oil spilled between the years 2007-2014 are highlighted along with a trend line showing an overall increase in production the past two years correlating with a decrease in spills for the same period. In 2010, approximately 590 million barrels of oil were produced, and including *Deepwater Horizon*, 5,000,271 barrels were spilled. In 2014 over 528 million barrels of oil were produced on the OCS compared to only 24 barrels being spilled in the same time frame.



"From 2007 to 2014, an average of ten oil spills releasing more than 50 barrels was reported on the OCS per year."

³¹ Spilled fluids can include crude oil, refined petroleum, synthetic-based drilling fluid, or other chemical or fluid mixtures resulting from topside equipment and hurricane-induced failures.

³² The majority of the spills in 2008 were a result of facility damage during Hurricanes Gustav and Ike.

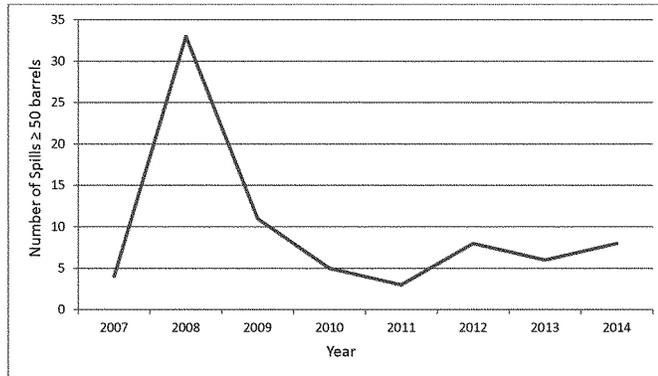


Figure 15: Spills on the OCS that were greater than or equal to 50 barrels per year.

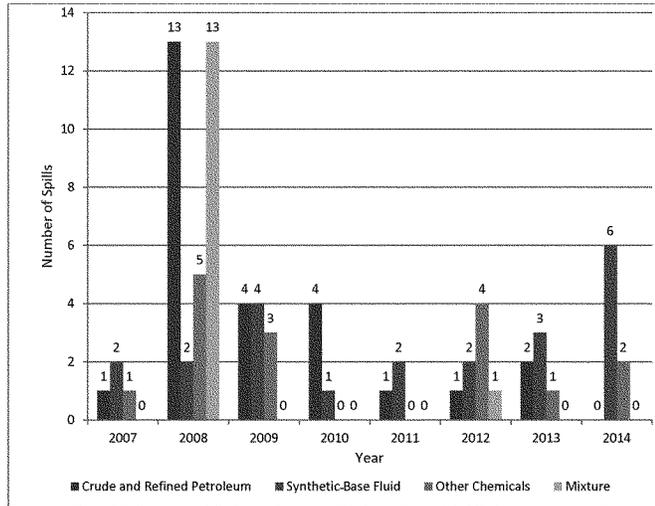


Figure 16. Number of OCS spills greater than or equal to 50 barrels shown by type of fluid released per year for 2007 to 2014. Other chemicals can include zinc bromide, calcium bromide, sodium bromide, asphaltene inhibitors and Methanol or Glycol.

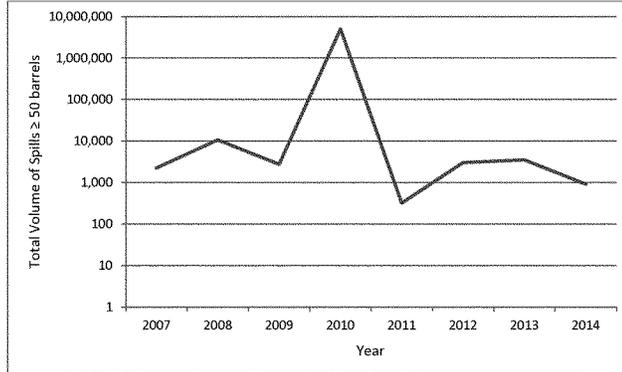


Figure 17: Total volume (in barrels) of major spills (over 50 barrels released) per calendar year on the OCS for years 2007 to 2014. The oil spill from the 2010 Macondo well blowout and oil spill is included. That spill was estimated at five million barrels.

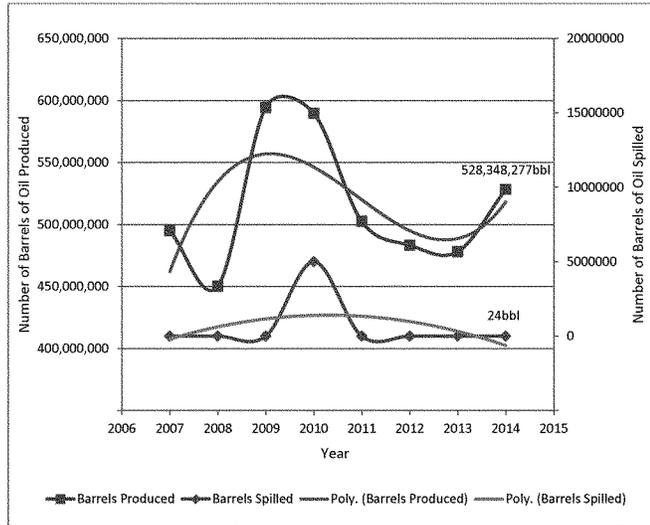


Figure 18: Total number of barrels of oil produced compared to total number of barrels of oil spilled on the OCS between 2007-2014.

Lifting Incidents

The Bureau requires that all incidents involving crane or personnel/material handling operations be reported, pursuant to 30 CFR § 250.188(a)(8). Over the eight-year timeframe of this report, an average of 167 lifting incidents per year was reported. The lowest number of incidents was reported in 2010; however, incidents have tended to increase since 2010 (Figure 19). The trend of increasing lifting incidents is also observed when incidents are normalized to the number of offshore installations (Figure 20). In 2014, the calculated rate was one lifting incident per 12.7 installations.

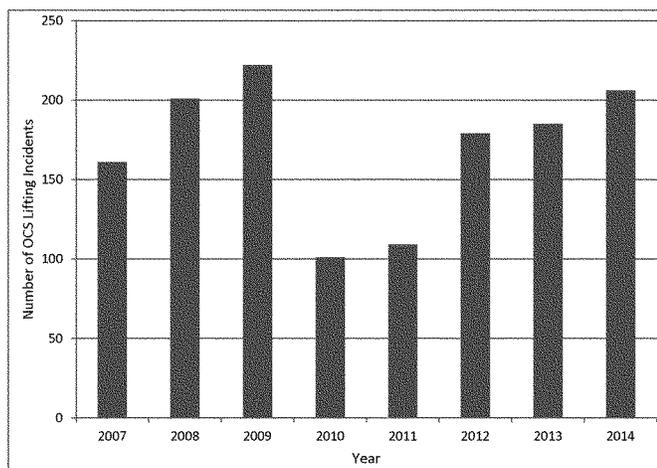


Figure 19: Lifting incidents on the OCS per year for 2007 to 2014.

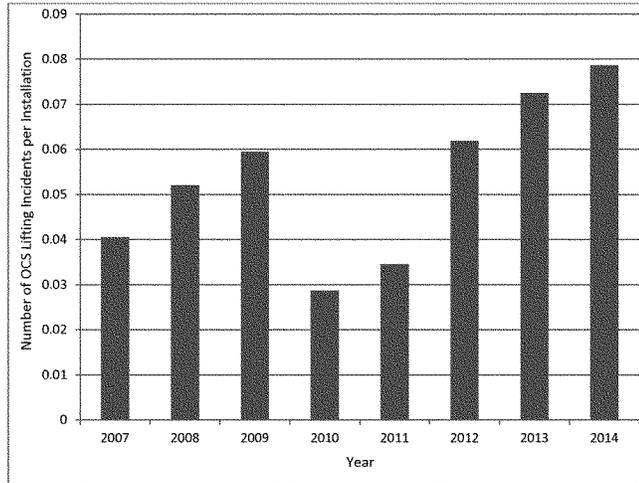


Figure 20: Lifting incidents on the OCS per installation, depicted by year for 2007 to 2014.³³

³³ The normalized number includes all installations, which could include some idle platforms. In future reports, this number will be refined as better data is available. When idle platforms are excluded, the normalized numbers in this figure would increase.

Gas and Hydrogen Sulfide Releases

The Bureau requires that all gas releases that initiate equipment or process shutdown and all hydrogen sulfide (H₂S) incidents that meet the criteria in 30 CFR § 250.490(l) must be reported pursuant to 30 CFR §250.188(b)(2) and 30 CFR §250.188(a)(5). For this section, the number of releases in the figures below show gas and H₂S releases combined. An average of 22.5 release incidents per year was reported from 2007 to 2014. The fewest were reported in 2014, and the most were reported in 2008 (Figure 21). The number of H₂S releases declined by nearly 50 percent from 2013 to 2014.

When the number of release incidents in a year is normalized to the number of offshore installations, the trend of releases per installation is increasing (Figure 22). In 2014, the calculated rate was one release per 90 offshore installations.

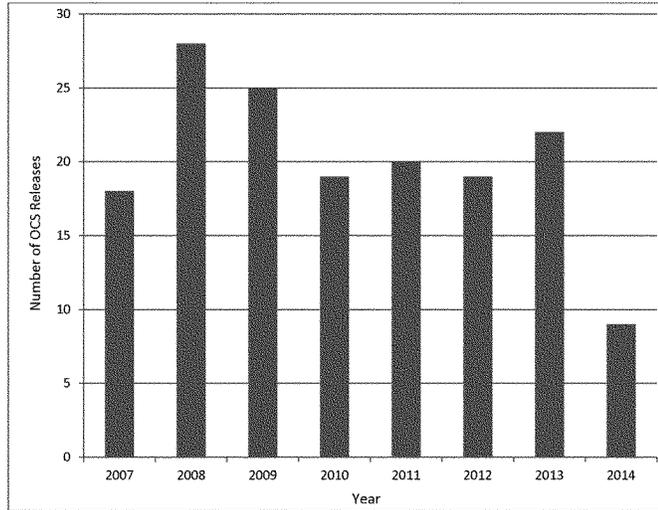


Figure 21: Releases of gas or H₂S on the OCS per year from 2007 to 2014.

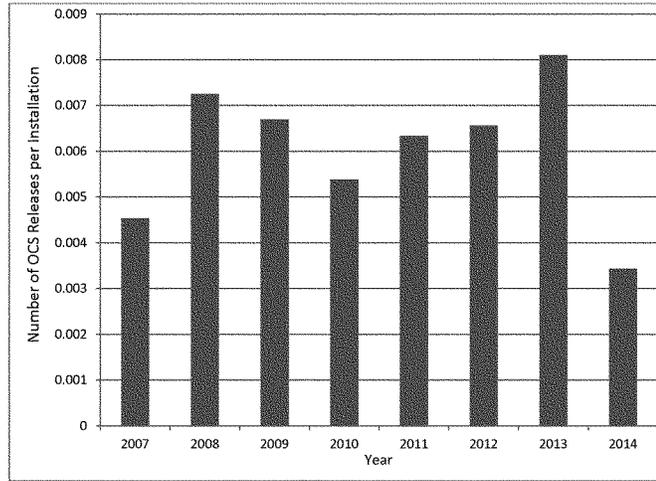


Figure 22: Releases of gas or H₂S on the OCS per installation per year from 2007 to 2014.

Muster for Evacuation

The Bureau requires reporting of all incidents requiring operations personnel on the facility to muster for evacuation for reasons not related to weather or drills, per 30 CFR § 250.188(b)(3). Over the eight-year timeframe of this report, an average of 45 musters for evacuation per year was reported. The fewest were reported in 2007, and the most were reported in 2013 (Figure 23). Both the total number of musters for evacuation (Figure 23), and the musters for evacuation per installation (Figure 24) have overall increasing trends, although there were fewer reported in 2014 than in 2013. In 2014, the calculated rate was one muster for evacuation per 53 offshore installations for the year.

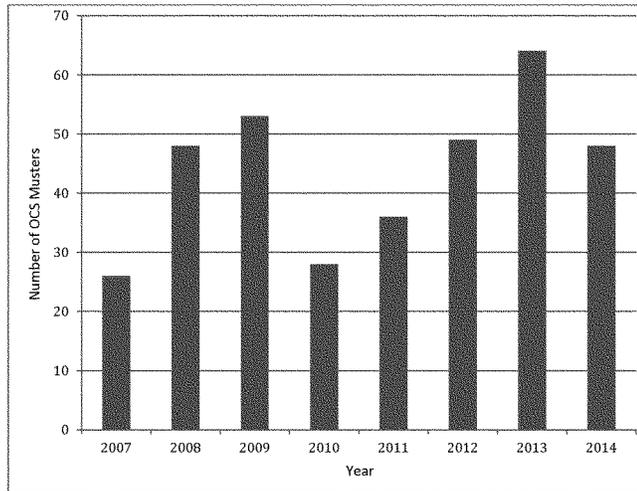


Figure 23: Musters for evacuation on OCS facilities by year for 2007 to 2014.

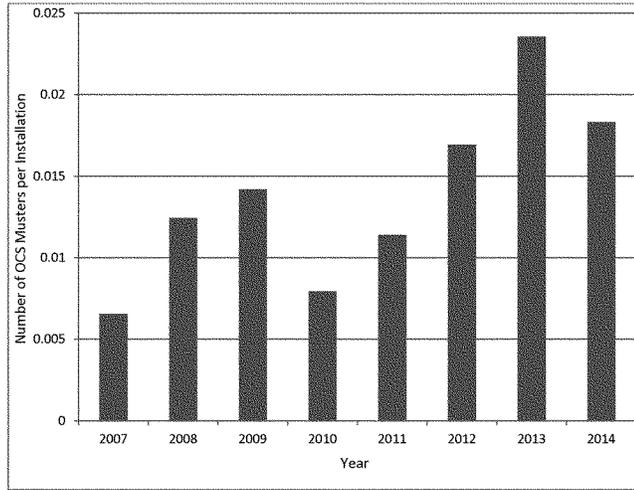


Figure 24: Musters for evacuation per OCS installation for each year from 2007 to 2014.

Investigations and Root Causes of Major Incidents

During 2014, BSEE conducted investigations of incidents and potential violations occurring during oil and gas operations on the OCS.³⁴ Incident investigations focused on identifying causes and developing recommendations to prevent the likelihood of recurrence of similar incidents. A majority of the incidents were determined to be caused, at least in part, by human performance factors, including communications, training, and equipment operation difficulties. In a minority of incidents, BSEE found equipment and/or design defects as causes (Table 8).

Table 8: Root causes of incidents investigated by BSEE.

Root Cause	Occurrence
Procedures – Human Performance Difficulty (HPD)	15.28%
Training - HPD	0.00%
Quality Control - HPD	0.00%
Communication - HPD	4.17%
Management System - HPD	4.17%
Human Engineering - HPD	19.44%
Work Direction - HPD	26.39%
Design – Equipment Difficulty (ED)	20.83%
Equipment/parts defects - ED	8.33%
Preventive/predictive maintenance - ED	0.00%
Management Systems - ED	1.39%
Tolerable failure - ED	0.00%

In Table 8, each of these categories represents a different type of incident, which are described as follows:

- Procedures – HPD: An incident where the most basic cause can reasonably be associated to a procedure not being used or followed, is incorrect, or being utilized incorrectly.
- Training – HPD: An incident where the most basic cause can reasonably be associated with training not being present, limited, or requiring improvement.
- Quality Control – HPD: An incident where the most basic cause can reasonably be associated to inspections not being required, inspection instructions or techniques needing improvement, or no hold point³⁵ is defined for inspections.
- Communication – HPD: An incident where the most basic cause can reasonably be associated to a total lack of communication, communication not being timely, information turnover needing improvement, or a misunderstood verbal communication(s).

³⁴ For a complete listing of BSEE investigations, please refer to: <http://www.bsee.gov/Inspection-and-Enforcement/Accidents-and-Incidents/Reports/>

³⁵ A hold point is a point in the repair or alternation process beyond which work may not proceed until the required inspection or testing has been performed and documented.

- Management System – HPD: An incident where the most basic cause can reasonably be associated to no standards, policies or administrative controls in place; standards, policies or administrative controls being ignored; inadequate oversight or employee relations; or corrective action system failures.
- Human Engineering – HPD: An incident where the most basic cause can reasonably be associated to complications with human-machine interface, work environment issues, over-complicated systems, or non-fault tolerant systems.
- Work Direction – HPD: An incident where the most basic cause can reasonably be associated to inadequate preparation, improper selection of an employee, or inadequate supervision during work.
- Design – ED: An incident where the most basic cause can reasonably be associated to inadequate design specifications or inadequate design review hazard identifications.
- Equipment/parts defects – ED: An incident where the most basic cause can reasonably be associated to equipment or parts being defective through procurement, manufacturing, handling, storage, or quality control.
- Preventive/predictive maintenance – ED: An incident where the most basic cause can reasonably be associated to a nonexistent or inadequate preventive/predictive maintenance program.
- Management Systems – ED: An incident where the most basic cause can reasonably be associated to repeat failures of equipment where a management system fails to have corrective actions implemented.
- Tolerable failure – ED: An incident where the most basic cause can reasonably be associated to a design failure that is considered tolerable.

For the most serious incidents that occur offshore, BSEE conducts panel investigations, which are in-depth investigations resulting in detailed findings and recommendations. These investigations are typically handled by a team of individuals including BSEE investigators (from BSEE's Investigations and Review Unit and from the regional offices), inspectors, and other experts. BSEE investigations will often include an assessment of companies' safety and compliance policies and procedures, as well as other information potentially relevant to the incident. Investigations typically involve a combination of witness interviews, evidence analysis (including forensics), review of company documentation, assessment of prior company performance, and other relevant information. Some panel investigations lead to recommended enforcement actions and/or referrals to other enforcement authorities. In 2014, BSEE completed two panel investigation reports and initiated two panel investigations.

BSEE incident investigations can also lead to the issuance of safety alerts,³⁶ a vehicle to inform industry participants about the circumstances surrounding an incident (or potential incident). In 2014, BSEE

³⁶ For a complete listing on BSEE Safety Alerts, please refer to: <http://www.bsee.gov/Regulations-and-Guidance/Safety-Alerts/Safety-Alerts/>

issued 11 safety alerts. In addition, in 2014 BSEE released two technical reviews analyzing certain failures of connectors and bolts used in critical equipment.

BSEE also conducts investigations of alleged violations by individuals and companies operating offshore. Typically, such investigations are initiated as the result of conditions discovered by BSEE inspectors and/or reported by offshore workers. BSEE investigations can result in the issuance of INCs, the assessment of civil penalties, and/or referral to other enforcement authorities. In 2014, BSEE conducted a number of these types of investigations and worked closely on multiple matters with the Department of the Interior Office of the Inspector General and other federal enforcement authorities.

The primary goal of every BSEE incident investigation is to determine what happened to cause an incident so that the Bureau can act to minimize the likelihood that a similar incident will occur in the future. A robust culture of safety can be achieved only when BSEE and industry have a clear understanding of how companies should act to prevent offshore incidents.

BSEE coordinates closely with the U.S. Coast Guard and other federal and state agencies to determine how to effectively respond to the incident and to determine which agency will be the primary investigator.

"The primary goal of every BSEE incident investigation is to determine what happened to cause an incident so that the Bureau can act to minimize the likelihood that a similar incident will occur in the future."



Looking Forward

The steady decrease in fatalities, major injuries, and other incidents since BSEE's inception in 2011 is encouraging. This trend, however, is countered by increases in fires and explosions per installation, major spills, releases of gas and hydrogen sulfide, and lifting incidents. These trends indicate that although there has been progress in making the OCS safer and protecting the environment, there is still progress to be made. BSEE is currently working on a proposed crane rule to reduce lifting incidents based on the increased number of lifting incidents observed on the OCS. Input from stakeholders once the rule is proposed will be critical to ensure it is as effective as possible.

Most root causes of incidents investigated by BSEE were linked to human performance difficulties, and the interface between people and engineered systems. This is a subject that both the Bureau and industry must keep in mind moving forward, if risk and incidents are to be reduced on the OCS. Developing a meaningful safety culture that permeates all actions offshore, and goes well above and beyond regulatory compliance is necessary to reduce risk.

BSEE believes that the primary responsibility for maintaining safety and environmental stewardship at all times lies with the companies operating on the OCS. In order to shift the burden of responsibility to industry, BSEE began to adjust governing regulations and compliance verification procedures to reflect, where appropriate, a performance-based approach. BSEE's implementation of the SEMS program cemented this new performance-based approach. Moving forward, BSEE will further adjust its oversight and align regulatory practices to reinforce safety conscious behaviors, discourage complacent behavior, and foster the development of a robust and positive safety culture.

Going forward, the Bureau will move towards a risk-based inspection approach, predicated on the idea that companies that have taken the responsibility for creating a culture of safety will have greater flexibility in operating in a safe and environmentally responsible manner. In 2015, BSEE will develop risk-based inspection approaches to compliance and oversight that complements SEMS and our current inspection program.

BSEE will add depth and capacity to our existing programs by realigning our internal structure to a national program model. This will facilitate clear, consistent, and readily accessible information to the industry and public. Part of this effort includes continuing to recruit and retain the best technical talent, and to bolster the Bureau's technical capacity. The Emerging Technology Assessment Center was established in Houston in 2014, and in 2015 the Bureau will fully build out the capabilities of this new center. The Bureau will bolster our capacity for analyzing data gained through incident reporting requirements, near-miss reporting, and real-time monitoring. The Bureau also will continue to work with industry to better understand their safety processes, so that we can mitigate and reduce risk. Through these initiatives, BSEE will continue to ensure that offshore exploration, production, and development occurs in a safe and environmentally responsible way, while actively working to improve offshore safety performance.

In 2015, the Bureau will continue to work to develop regulations, inspection guidelines, and procedures for the development of offshore renewable energy. The added capacity to the renewable energy inspection program will ensure that the appropriate regulatory structure will be in place to protect the safety of workers and the environment.

BSEE will continue to share lessons learned and best practices with international offshore oil and gas regulators, both with organizations such as the International Regulators Forum, the Arctic Council and the Arctic Offshore Regulators Forum, and through bilateral and multilateral engagements with other countries around the world. The Bureau will continue to focus on strategic engagement with countries,

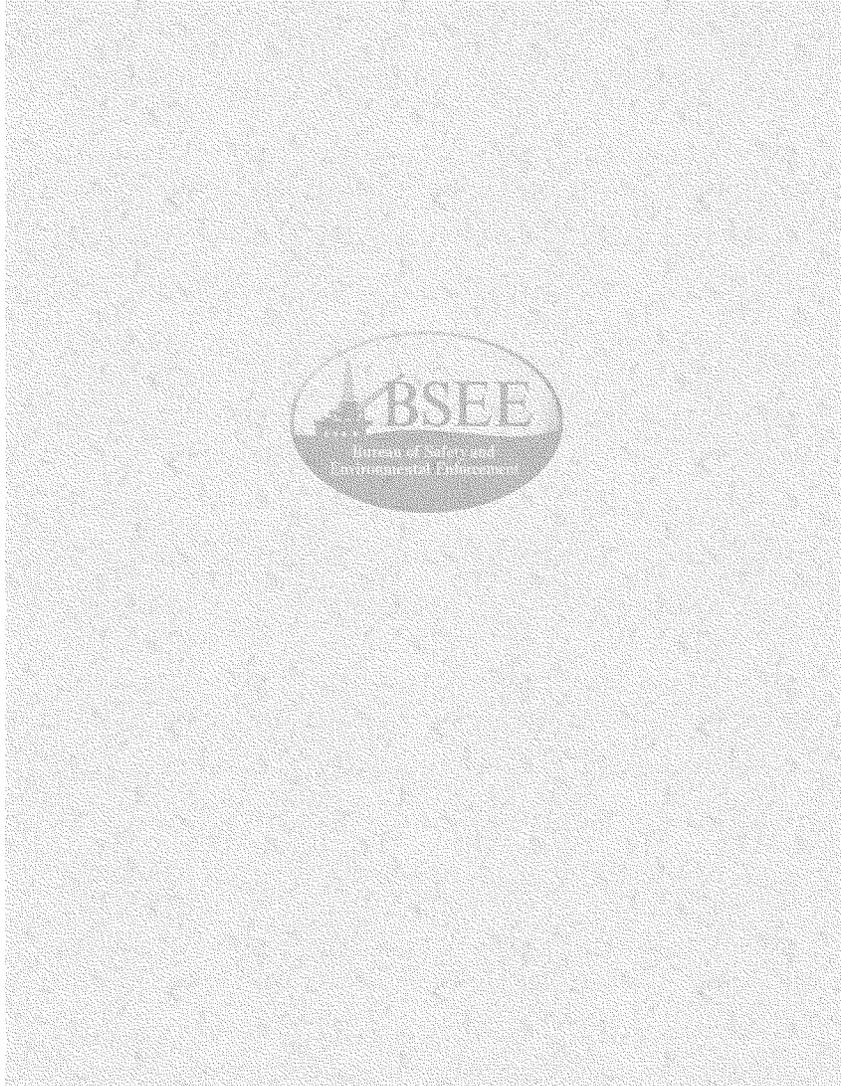
such as Canada and Mexico, that share boundaries with the United States. In particular, the international program will work to implement the terms of the Transboundary Agreement that BSEE administers with the U.S. Bureau of Ocean Energy Management and the Agencia de Seguridad Energética y Ambiente (ASEA) in Mexico.

In the year ahead, BSEE staff will be working with stakeholders to share lessons learned and best practices, looking for ways to get better information through SEMS and our near-miss reporting system, while continuously working to fulfill the needs of the BSEE mission. The Bureau will be also working with industry on the latest technological advances, all of which come together to help reduce risk offshore. The risks inherent in offshore activities will never be fully eliminated, but through this work, BSEE can substantially reduce those risks.



"It is my belief that we can never relax our focus on safety. The trends we see in the first BSEE Annual Report show that progress is being made to improve safety and reduce risk offshore but there is still more work to be done and further improvements to be made."

Brian Salerno
Director



The CHAIRMAN. Thank you, Mr. Salerno.
Mr. Milito, welcome.

**STATEMENT OF ERIK MILITO, GROUP DIRECTOR, UPSTREAM
AND INDUSTRY OPERATIONS, AMERICAN PETROLEUM IN-
STITUTE**

Mr. MILITO. Thank you, Chairman Murkowski, Ranking Member Cantwell, and members of the committee.

My name is Erik Milito, and I am director of Upstream and Industry Operations for the American Petroleum Institute. My responsibilities include advocating for the advancement of safety in offshore operations.

Safe, responsible energy development in the Gulf of Mexico and beyond is vital to the U.S. economy and job growth and to U.S. energy and national security. The U.S. Energy Information Administration projects that our economy will rely upon oil and natural gas for more than half of our energy needs for decades to come, and the U.S. offshore will continue to play a key role in supplying those resources.

Today, the offshore accounts for about 1.4 million barrels of oil per day and makes up about 16 percent of our nation's total oil production. As we move forward, we must work to ensure that we have a regulatory system in place for the U.S. offshore, including offshore Alaska, that promotes the safe development of our energy resources.

Fortunately, today, we have a strong system in place to safely develop those resources. Over the past half-decade, joint efforts from our industry and the Federal Government have resulted in significant enhancements in the safety of offshore operations. Our thoughts and prayers continue to go out to the families who lost loved ones in 2010, and a comprehensive review by the industry after the 2010 spill has led to improved spill prevention, subsea containment, and response capabilities.

More than 100 exploration and production industry standards were developed or enhanced, including standards for safety and environmental management, well design, blowout prevention, and spill response. And today, our industry can rapidly deploy the most advanced subsea well containment technology available.

We have also created the Center for Offshore Safety to advance our industry's safety improvement goals. The Center for Offshore Safety builds on our industry's strong safety culture through the completion of safety system audits and by sharing best practices for safe and responsible energy production, some of which have already been incorporated into Federal regulations. The center has also implemented data collection and reporting and has issued two annual reports providing detailed and transparent information for lessons-learned efforts.

Likewise, the Government has stepped up to the plate by drafting various new regulations, including new rules related to safety and environmental management systems, well integrity, and blowout prevention. The interim final drilling safety rule was published in October of 2010 and revised in 2012. The Government also has new requirements in place for the demonstration of adequate spill response capability and well containment resources. Congress has

taken positive steps as well by dedicating funding for offshore enforcement activities.

However, we remain concerned about various regulatory activities related to offshore energy development, specifically proposed rules for well control and Arctic operations. In both cases, certain proposed requirements may not appreciably improve safety in offshore operations. In fact, various provisions of the proposed well control rule could actually serve to increase risk and reduce safety.

Our goal is to constantly improve operations integrity and decrease risk, but many of the requirements proposed in this rule could create unintended consequences that would shift risk rather than decrease it.

As it relates to the Arctic, it is clear we have time to make sure that any regulations that are published achieve the objectives of promoting energy development and protecting our workers and the environment. The National Petroleum Council, at the request of the Secretary of Energy, released a report earlier this year that concluded, "oil and gas exploration and development in the Arctic is extensively regulated."

Progressing offshore development in the Arctic would require around 60 permit types through ten Federal agencies. Regulations should be adaptive to reflect advances in technology and ecological research and achieve an acceptable balance considering safety, environmental stewardship, economic viability, energy security, and compatibility with the interests of local communities. Prescriptive regulation may inhibit the development of new, improved technologies by suppressing the potential opportunity that drives advancement.

As the Government finalizes any of its pending regulations, it should ensure that it is not implementing overly prescriptive requirements that will serve to inhibit innovation and technology advancement. Our industry has a proven track record of working with the Federal Government to improve offshore safety. We remain optimistic that dialogue between the Government and industry experts will continue, and the final well control rule will rely on the best technical knowledge to achieve the mutually desired safety objective.

With the proposed Arctic rule, the Government has denied our requests for continued engagement and dialog, but we are hopeful they will reconsider.

Thank you for your time, and I look forward to your questions.
[The prepared statement of Mr. Milito follows:]

**“Hearing to receive testimony on the Well Control Rule and other regulations
related to offshore oil and gas production”**

U.S. Senate Committee on Energy and Natural Resources

Testimony, Erik Milito

Group Director, Upstream and Industry Operations

American Petroleum Institute

December 1, 2015

Good morning Chairman Murkowski, Ranking Member Cantwell, and members of the committee.

My name is Erik Milito, and I am the Director of Upstream and Industry Operations for the American Petroleum Institute. My responsibilities include advocating for and advancing offshore safety. Following the Macondo incident, I helped to organize several industry task forces to work collaboratively with the government to improve safety in the offshore in a sensible way. The fruits of those labors are evident in the changes that have already occurred in offshore safety over the past five plus years. I am also extensively engaged in the development of API standards that promote safe and responsible development of the nation’s offshore oil and natural gas resources.

API has more than 625 member companies, which represent all sectors of America’s oil and gas industry. Our industry supports 9.8 million American jobs and 8 percent of the U.S. economy. We appreciate the opportunity to participate in today’s hearing.

I’d like to take a moment to remember the 11 workers who lost their lives on April 20, 2010, as well as their families. Those workers are a constant reminder that we must continue to improve safety in our industry. The industry is committed to a goal of zero fatalities, zero injuries and zero incidents, and our industry takes any safety or environmental incident as a call to learn and to improve technology, training, operational procedures, and industry standards and best practices.

Immediately after the Macondo incident in the Gulf of Mexico (GOM), the U.S. oil and natural gas industry (Industry) launched a comprehensive review of offshore safety to identify potential improvements in spill prevention and intervention and

response capabilities. Four Joint Industry Task Forces (JITFs) were assembled to focus on critical areas of GOM offshore activity: the Joint Industry Offshore Operating Procedures Task Force (Procedures JITF), the Joint Industry Offshore Equipment Task Force (Equipment JITF), the Joint Industry Subsea Well Control and Containment Task Force (Subsea JITF), and the Joint Industry Oil Spill Preparedness and Response Task Force (OSPR JITF). Teams were composed of industry expert members of the American Petroleum Institute (API), International Association of Drilling Contractors (IADC), Independent Petroleum Association of America (IPAA), National Ocean Industries Association (NOIA), and the United States Oil and Gas Association (USOGA). Sessions began in early spring of 2010 to provide recommendations to the U.S. Department of the Interior (DOI) in the areas of prevention, intervention and oil spill response.

The JITFs were not involved in the review of the incident; rather they brought together Industry experts to identify best practices in offshore drilling operations and oil spill response, with the definitive aim of enhancing safety and environmental protection. The Procedures, Equipment, and Subsea JITFs, as they are called, all issued final reports in March of 2012 while the OSPR JITF released a progress report in November of 2011, with projects still ongoing. The ultimate goal for these JITFs is to improve Industry drilling standards to form comprehensive safe drilling operations, well containment and intervention capability, and oil spill response capability; not only through evaluation and revision of Industry guidelines and procedures, but also active engagement with regulatory processes.

The JITFs worked with trade associations, DOI's Bureau of Safety and Environmental Enforcement (BSEE) and Bureau of Ocean Energy Management (BOEM) and their predecessor organizations, U.S. Coast Guard (USCG), U.S. Environmental Protection Agency (EPA), National Oceanic and Atmospheric Administration (NOAA), National Response Team (NRT), the independent presidential commission (National Commission on the *Deepwater Horizon* Oil Spill and Offshore Drilling), the Chemical Safety Board (CSB), the National Academy of Engineering (NAE), members of Congress, and others as they considered the Macondo incident and potential changes in Industry regulation.

The work of the JITFs was, and is, instrumental in creating enhanced safety in offshore oil and gas operations in each of the key areas: prevention, intervention

and containment, and response. The work is reflected in the revised regulatory framework and in the development of new and revised, world class, industry technical standards. In addition to the work of the JITFs, industry established the Center for Offshore Safety (COS) to foster safety culture and share lessons learned across industry, and the Marine Well Containment Company (MWCC) and HWCG in 2010 to provide containment technology and response capabilities for the unique challenge of capping a subsea well. Please see Appendix A for a full summary of the work of the JITFs, as well as a summary of industry standards development related to offshore safety that has been instrumental in advancing offshore safety. Please also see attached a brochure entitled "Improvements to Offshore Safety by Industry and Government," which describes the concrete actions taken by both industry and government to elevate safety over the past several years.

Based upon the above, it is undeniable that the environment for U.S. OCS oil and natural gas operations is safer today than it has ever been for both the Gulf of Mexico and Alaska, as well as for the Atlantic and Pacific regions. However, we are greatly concerned that a new rule proposed by the Bureau of Safety and Environmental Enforcement on April 17, 2015, entitled "Oil and Gas and Sulphur Operations in the Outer Continental Shelf - Blowout Preventer Systems and Well Control", could actually increase risk and decrease safety in offshore operations. While much of the proposed rule is sensible and effective for addressing risk, there are various, significant elements of the rule that could do the opposite – increase risk. We are also very concerned that the Alaska specific rules that were proposed jointly by BSEE and BOEM will likewise not appreciably enhance safety. We are committed to working with the government to achieve the mutually desired objective of safety. We are encouraged by the opportunity to meet with BSEE on December 7 to further discuss concerns with the proposed Well Control Rule and request a similar opportunity to work with BSEE and BOEM regarding our concerns with the proposed Arctic regulation. We want to get these rules right, but we all should ensure that artificial deadlines do not take precedence over the substance of safety.

NATIONAL IMPORTANCE OF ALASKA OIL AND NATURAL GAS RESOURCES

Alaska is home to some of the most prolific oil and natural gas reserves in the United States. Production in the state's North Slope once supplied about a

quarter of total U.S. oil production.¹ An estimated 30 percent of the nation's known recoverable offshore resources are in Alaska's waters.² However, 61 percent of Alaska's land is controlled by the federal government, which has erected one obstacle after another to energy development.³ Even promising areas specifically established under federal policy as energy development zones remain largely off limits.

Oil and natural gas development is the backbone of Alaska's economy, supporting one-third of all state jobs and contributing more than \$6 billion in labor income.⁴ Alaska oil and natural gas production has been a lifeline for the U.S. energy supply, offsetting much of the mid-1980s production declines experienced in the Lower 48 and transporting 17 billion barrels of oil through the Trans-Alaska Pipeline south to the Pacific coast.⁵ Virtually all of that production took place on state and native lands. Yet the available geologic information strongly suggests that the resource potential in federal areas may far exceed the potential of state lands. Expanding access in resource-rich areas like National Petroleum Reserve Alaska (NPR-A), designated areas in the Arctic National Wildlife Refuge (ANWR) and offshore is vital not just for Alaska's economy but for the nation's long-term energy security.

Failure to harness the energy potential in the Arctic Ocean today could have significant consequences for the nation's long-term energy security. The world's largest remaining conventional, undiscovered oil and natural gas reserves -- estimated at 13 percent of recoverable oil and 30 percent of recoverable natural gas resources -- await development in the Arctic.

Estimates indicate the Arctic's Beaufort and Chukchi seas have more technically recoverable oil and natural gas than the Atlantic and Pacific coasts combined -- with the Chukchi Sea alone home to 29.04 billion barrels of oil equivalent,

¹ API, "Alaska: A State of Energy -- A History of Energy," <http://www.energyandalaska.com/#/?section=astate-of-energy>

² Alaska Oil and Gas Association, "Facts and Figures," <http://www.aoga.org/facts-and-figures>

³ www.murkowski.senate.gov, "Landlocked: Murkowski Explains Alaskans' Access Frustrations," March 2015 http://www.murkowski.senate.gov/public/index.cfm/presreleases?ContentRecord_id=B07565EF-7CE7-415E-8079-24F94F91831F

⁴ Alaska Oil and Gas Association, "The Role of the Oil and Gas Industry in Alaska's Economy," May 2014 http://www.aoga.org/sites/default/files/news/aoga_final_report_5_28_14_0.pdf

⁵ API, "Alaska: A State of Energy -- Energy and Infrastructure, TAPS," <http://www.energyandalaska.com/#/?section=astate-of-energy>

according to government estimates. A 2011 study by the Anchorage firm Northern Economics projects that developing resources in the Beaufort and Chukchi Seas could generate as many as 50,000 jobs.⁶

Although about 700 leases have sold for offshore oil and natural gas exploration in Alaska since 2005 – generating billions in revenue for the federal government⁷ – only one well has been drilled to production depth due largely to delays and continually evolving restrictions imposed by the federal government. Seven years of repeated federal obstacles elapsed before Royal Dutch Shell was allowed to proceed with drilling an exploratory well in 2015. The company’s decision to discontinue the project was based partly on the well’s output, but Shell also cited the “challenging and unpredictable federal regulatory environment in offshore Alaska” in its decision.⁸

Interior Secretary Sally Jewell has stated, “The Arctic is an important component of the administration’s national energy strategy, and we remain committed to taking a thoughtful and balanced approach to oil and gas leasing and exploration offshore Alaska.”⁹

Recent history does not demonstrate the balanced, forward-looking approach necessary to fulfill the potential of Arctic energy. Four Chukchi and Beaufort Sea lease sales that were included in the 2007-2012 Leasing Program and proposed to take place between 2009 and 2012 were cancelled. Only three lease sales are included in the current 2012-2017 Leasing Program, and the Interior Department announced in October 2015 that it would cancel those and deny lease extension requests.¹⁰ Only one lease sale for each of the Beaufort and Chukchi seas has been proposed for the 2017-2022 Leasing Program. Collectively, these decisions

⁶ Northern Economics, “Economic Analysis of Future Offshore Oil and Gas Development: Beaufort Sea, Chukchi Sea, and North Aleutian Basin,” March 2009 <http://northerneconomics.com/wp-content/uploads/2015/04/Shell-OCS-report-final-web.pdf>

⁷ API, “Alaska: A State of Energy – Federal Policies of Limitation, Onshore,” <http://www.energyandalaska.com/#/?section=astate-of-energy>

⁸ www.shell.com, “Shell updates on Alaska exploration,” September 2015 <http://www.shell.com/global/aboutshell/media/news-and-media-releases/2015/shell-updates-on-alaska-exploration.html>

⁹ www.interior.gov, “Department of Interior Affirms 2008 Chukchi Sea Lease Sale,” <http://interior.gov/news/pressreleases/department-of-the-interior-affirms-2008-chukchi-sea-lease-sale.cfm>

¹⁰ API, “API statement regarding Obama administration decision to cancel 2016 and 2017 Arctic oil lease sales,” October 2015 <http://www.api.org/News-and-Media/News/NewsItems/2015/October-2015/API-statement-on-admin-cancellation-of-arctic-lease-sales>

represent a system of regulatory and permitting unpredictability and uncertainty that continues to undermine investment decisions. Regulatory certainty combined with routine opportunities for leasing are necessary to secure the promise of Alaskan oil and natural gas production in federally controlled areas.

To boost American energy security in the coming decades, development in the Arctic must begin right away. According to a report from the National Petroleum Council, "Given the resource potential, and long timelines required to bring Arctic resources to market, Arctic exploration today may provide a material impact to U.S. oil production in the future, potentially averting decline, improving U.S. energy security, and benefitting the local and overall U.S. economy."¹¹ Decades of experience operating in Arctic environments demonstrates the oil and natural gas industry has the technology and expertise to safely develop Arctic offshore resources.

Canada, Russia and Norway are already active in Arctic offshore exploration. A consistent, forward-thinking regulatory framework that prioritizes regularly scheduled lease sales is necessary to enhance U.S. energy security and maintain America's position as a global energy superpower.

The regulatory framework raises many concerns for the industry, given the new requirements proposed jointly by BSEE and BOEM for exploratory drilling and related operations on the Outer Continental Shelf (OCS) seaward of the State of Alaska (Alaska OCS). The proposed regulations were published in the Federal Register February 24, 2015 at 80 FR 9915 (Volume 80, Number 36, Pages 9915–9971). A copy of the API, U.S. Chamber of Commerce and National Association of Ocean Industries comments is attached for the record.

As stated above, the search for energy resources in the Arctic is not new. Nearly a century of industry operations in the region demonstrates that exploration and development of oil and natural gas resources in the Alaska OCS can take place in a safe and environmentally responsible manner; can enable the protection of habitat, wildlife, communities and subsistence lifestyles. Currently, Arctic production accounts for 25 percent of the world's natural gas and 10 percent of its oil.

¹¹ National Petroleum Council, "Arctic Potential: Realizing the Promise of U.S. Arctic Oil and Gas Resources," March 2015 http://npcarcticpotentialreport.org/pdf/AR-Executive_Summary-Final.pdf

Unfortunately, the BSEE-BOEM Arctic rules package imposes prescriptive requirements which presume that one set of assumptions will universally apply to any given location. Performance-based rules, on the other hand, would allow an operator to minimize risks by designing a well program specific to the landscape, ecosystem, ice conditions, water depths and weather of that particular well. Some of the specific concerns with the proposed Alaska regulations:

- The rule requires a relief well and doesn't consider other barrier technologies. Instead, API urges the adoption of a regulatory approach that focuses on prevention and that considers fit-for-purpose response planning alternatives to respond to potential loss of well control.
- The rule shifts responsibility for operational decisions away from the rig to company personnel or even agency personnel not working onsite. Onsite personnel have the best understanding and most complete picture of the current operation, key risks and critical considerations. In addition, their experience in active operations provides them with the judgment to make effective real-time decisions within the bounds specified by the Operators governing procedures and operations integrity guidelines. This responsibility includes full control of the operations and the full authority to stop activities at any time. Instead, API urges that in the event BSEE seeks to direct active drilling operations, further clarification is required on the associated responsibility, accountability and liability that would be assumed in the event of any incidents that occur as a direct result of those actions.
- The proposed rules do not consider alternatives to floating rigs, even though floating rigs are not the only means to drill a well, which is yet another example of the rules using prescriptive rules that require particular equipment to the exclusion of other approaches that could be safely and effectively used. If the regulatory focus is on floating rigs, then the rules should be applicable only to floating rigs. Alternatively, the rules could adopt a broader, more flexible and performance-based approach such as found in rules applicable to other areas of the OCS which do not prejudice the choice of drilling platforms.

- The proposed rules introduce an additional and redundant layer of regulation for cuttings discharge, which are already regulated by the EPA under the Clean Water Act. The proposed rules add provisions requiring the operator to capture all petroleum-based mud and associated cuttings to prevent their discharge into the marine environment during exploratory drilling operations on the Arctic OCS, and grant discretionary authority to BSEE's regional supervisor to restrict discharge of water-based muds and cuttings. The Clean Water Act grants EPA jurisdiction over all facilities which discharge pollutants from any point source into waters of the United States. This includes drill cuttings discharged from a rig into waters of the U.S. in Arctic regions. Under EPA regulations, control is already established to ensure that when cuttings discharge is permitted the associated impact to the environment is reduced to acceptable levels.
- BSEE and BOEM underestimate the cost of the proposed rules and the economic analysis put forward significantly and systematically underestimates the potential impact to industry. The assessed ~\$1 billion cost to industry over 10 years fails to address the impacts of shortening the effective drilling season (driven primarily by a same-season relief well requirement) and imposing specific design, logistics and operating requirements. The estimated cost to industry is at least \$10 - 20 billion, and it could potentially be higher. Such a cost burden would not just deny the nation energy security from developing its oil and gas resources, but it would also prevent economic development in Alaska and across the country from an estimated 145 billion in new payroll for U.S. workers and \$193 billion or more in new local, state, and federal government revenue. In addition to the Arctic rules proposed, on April 13, 2015, BSEE proposed new rules for all OCS areas, including the Arctic OCS, that are focused on Blowout Preventer Systems and Well Control. The proposed rules significantly alter the current regulations in both content and structure and overlap in numerous areas with the proposed Arctic OCS rules. The heightened requirements that will result with the final publication of the BOP and Well Control rules will impact considerations for the Arctic OCS rules. Because of this, API requests that the comment period of the Arctic OCS rules be re-opened after the BOP and Well Control final rules are published. This will ensure all parties fully understand the base regulatory

regime for OCS areas and enable more informed decisions to be made regarding incremental Arctic OCS requirements.

UNINTENDED SAFETY CONSEQUENCES OF BSEE'S PROPOSED WELL CONTROL RULE

As previously stated, BSEE proposed regulatory changes to Blowout Prevention Systems and Well Control requirements in 30 C.F.R. part 250 on April 17, 2015, in a 264 page notice of proposed rulemaking entitled, "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control." The original notice allowed 60 days for public comment, after dozens of letters requesting an extension of an additional 120 days, BSEE granted a 30 day extension for comments until July 16, 2015.

API and 6 of our fellow trades, IADC, the Independent Petroleum Association of America (IPAA), NOIA, the Offshore Operators Committee (OOC), the Petroleum Equipment & Services Association (PESA), and the USOGA drew on the expertise of over 300 subject matter experts from more than 70 companies who expended tens of thousands of person hours to provide BSEE a technically-based set of comments to aid in its efforts to create a robust and effective well control rule. Our comments are provided for the record. Even after all these resources were spent, we still believe additional time to review and comment on this lengthy and complex rulemaking was needed and, had it been provided, would have further contributed to the proposal's development. In the absence of additional time to review and comment on this complicated and lengthy rulemaking, Industry has repeatedly asked for substantial industry-regulator engagement to generate and implement a workable and effective set of rules. A small number of meetings occurred in mid-September but they were extremely limited in time and scope. However, we remain optimistic that technical discussions with BSEE and Industry on December 7 will serve to improve the final rule.

Our members recognize that offshore operations must be conducted safely and in a manner that protects the environment. The U.S. offshore industry has advanced the energy security of our nation, and contributed significantly to our nation's economy. Our goal is for operations integrity and fit-for-risk designs, and we are concerned that many of the requirements in the proposed rule would increase environmental and safety risk in drilling operations rather than improve safety. In addition, we are concerned that the proposed rule would materially impair the

ability to maintain current production operations, reduce future development and production or result in taking of leases and stranding of valuable reserves. To avoid these negative unintended consequences it is imperative that BSEE and industry collaborate to develop rules that are more workable and effective.

Some of the specific concerns with the proposed Well Control regulations:

- A one-size-fits-all approach does not recognize the variability of operations and engineering specific to each well. Industry currently uses a risk management process and designs and operates wells according to the needs of the particular well, all in consultation with BSEE.
- The proposal has strict requirements on the “drilling margin” used for all wells regardless of any specific well characteristics.
 - The “drilling margin” is the difference between the weight of drilling mud present in the well to keep fluids and hydrocarbons from flowing into the well and reaching the surface and the weight that would cause the rock formations being drilled through to break down. In short, this strict, prescriptive requirement denies the driller the ability to make risk-based decisions, in consultation with BSEE, and may create wellbore stability problems that add unnecessary risk to personnel, the environment and facilities.
- A number of the proposal’s prescriptive requirements will only serve to stifle innovation and delay implementation of new technologies that could improve safety and operations.
- Under the proposed rule, BSEE staff who are not on the drilling rig are given an increased role in day-to-day operations and critical decision making processes. Their role supplants that of the offshore rig personnel who have the most complete picture of the current operation and the key risks and critical considerations needed to take appropriate actions. The use of real-time monitoring must not supplant the ability of the rig personnel to make effective real-time decisions using their experience in active operations which is critical to maintaining safe operations and responding to emergency operations.
- Strict adherence to the Overbalanced Packer Fluid provisions could prevent the production of many wells that are safely produced today or require reduced flow capacity.
- Increasing mud weight during cement operations increases the risk of lost circulation and may result in failing to attain the required “top of cement”

depth. Although the higher applied pressure increases the critical gel strength, this pressure is not transmitted through the cement slurry during the slurry's Critical Gel Strength Period. Prohibiting the judicious use of unweighted pre-flushes as a tool to reduce equivalent circulating density and to improve the chance of a successful cement job is not justified.

- Industry fully supports the incorporation by reference of API Standard 53 Blowout Prevention Equipment Systems for Drilling Wells (API 53), but does not support those requirements that exceed those found in API 53. API 53 was developed and published post-Macondo through a comprehensive, accredited process to address blowout prevention equipment systems for drilling wells and should be the basis of the new rule. Any deviations from API 53 are a concern. A copy of API 53 is available on API's website for online review.
- Requiring that the BOP and every associated system and component be completely disassembled and a detailed physical inspection be performed all at one time, every five years for BOP inspection and certification is unnecessary, BSEE provides no evidence to suggest that this would increase safety.
- The additional accumulator requirements are both confusing and unrealistic. API 53, proposed for incorporation by reference, dictates the sizes of the surface tanks and pumps systems relative to accumulator capacity. The increase in capacity, proposed by this rule, will force associated increases in other components which are already generally constrained by available space. The resulting sprawling, piecemeal systems would likely be less safe and inefficient.
- Expanded subsea testing of the Deadman/Autoshear beyond current practices and what is defined in API 53, could:
 - increase risk of harm to personnel;
 - negatively impact the environment; and
 - cause unrecoverable damage to the rig or well.

Every time you operate the device you introduce the risk of limiting the vessel's capability to actually disconnect. To meet the proposed requirement on some systems, both pods would need to be powered down thus exposing the vessel to drift/drive-off damage.

- Prescriptive proposed requirements for ram configuration and installation of blind-shear rams could lead to the loss of additional pipe rams which in

some cases may be preferential. A risk assessment should be conducted and is the correct tool to determine the placement of all rams.

- The ROV panel requirements of this proposed rule would require the installation of more than 20 new receptacles in addition to the 23 existing panels installed on a typical system in use today. Enabling these additional ROV functions would require additional shuttle valves, hoses, tubing, and receptacles. This would introduce more potential leak paths, trip hazards, and viewing obstructions along with the associated additional maintenance for these components. Industry believes that the operational risks introduced outweigh the rewards of this additional emergency functionality.
- The requirement to test BOPs under the most extreme conditions is neither practical nor safe to perform. This raises concern with BSEE's focus on worst case events rather than early detection and prevention.
- The Mechanical Integrity Assessment Report is an unnecessary administrative burden with no tangible risk reducing impact since the same requirements exist in the regulations that require an APD and a SEMS.
- In cases where provisions in the proposed rule could realistically be implemented, the timeframe provided is unrealistic, effectively creating a drilling moratorium in the interim. This is because the proposed compliance timeframe of three months after publication of the final rule includes requirements for new equipment that cannot feasibly be manufactured, procured and installed in so short a time. In addition, operators and contractors may need to re-engineer drilling rigs to accommodate new equipment.
- The proposed regulation would place additional administrative burdens on BSEE while the agency is already struggling with tight budgets and limited resources resulting in a "just-in-time" permitting environment.

In addition to the topics listed above, the vast difference between the BSEE economic analysis of this proposed rule and the third party and Industry analyses must be resolved. BSEE estimated the 10-year incremental cost of the rule at approximately \$883 million. An independent cost assessment performed by Blade Energy Partners (Blade) and Quest Offshore (Quest) estimated cumulative 10-year costs at approximately \$32 billion. The Quest/Blade economic assessment of the proposed rule on Gulf of Mexico development projected:

- a reduction of the number of wells drilled per year by an average of 26%;
- a reduction of capital investment in the Gulf by an average of 10% per year;
- reduced Gulf of Mexico oil and natural gas production of 0.5 million barrels of oil equivalent by 2030;
- a reduction of the total employment supported by Gulf development of over 50 thousand jobs by as early as 2027;
- a ten-year cumulative reduction of US GDP by \$27 billion; and
- a ten-year cumulative loss of government revenue of \$10 billion.

We also encourage BSEE to closely examine the use of absolute language used throughout the proposed rule such as the use of words like “any” and “all” which can create unintended burden and confusion during implementation due to varying interpretations.

The Industry appreciates the opportunity to continue to discuss our concerns with BSEE. Further engagement should be the most efficient method of developing final regulations and address the existing fundamental technical and economic flaws in the proposed rule, and allow constructive development of rules that promote safety and protection of the environment, as well as, economic growth, innovation, competitiveness and job creation.

ADDITIONAL REGULATIONS RELATED TO OFFSHORE OIL and GAS PRODUCITON

In addition to the well control rule, there are other regulations and policy matters that BOEM and BSEE are contemplating that could impact companies’ OCS operations. In particular, pending changes to air quality regulations and to the criteria used to assess a company’s financial capability to meet its OCS lease obligations have the potential to impose potentially unnecessary additional burdens on industry.

Regarding the pending changes to OCS air regulations, the authority provided to DOI via the OCS Lands Act to implement air quality regulations has limited focus and the proposed rule should be consistent with the limited authority provided to DOI by Congress. While it may be appropriate to revise the current BOEM air quality regulatory program to reflect current NAAQS promulgated by USEPA for onshore areas, an expanded air quality regulation (e.g., new monitoring/reporting

requirements, lower exemption thresholds, grouping of emission sources, etc.) is not warranted to assure offshore sources do not have a significant impact on onshore air quality. BOEM is proceeding with this rulemaking prior to the conclusion of ongoing modeling studies intended to better understand whether any additional emission control for offshore operations are warranted. BOEM should delay any regulatory amendments to reflect the conclusions from these studies

In terms of the proposed changes to criteria to determine the financial ability of companies to carry out their obligations on leases, rights-of-way (ROWs), and rights-of-way and easements (RUEs) issued on the Outer Continental Shelf (OCS), BOEM and industry have been working closely on these changes and BOEM has embraced many of industry's recommendations. However, we remain concerned that BOEM has not provided a clear definition of the problem that the agency is trying to solve nor has there been justification provided as to the need for major changes the existing regulatory framework. Any changes should be designed so as not to undermine the current framework that encourages prudent operations or to introduce unintended and unnecessary consequences. Some of the changes BOEM is contemplating provide another example of BOEM's practice of creating new binding requirements outside the rulemaking procedures of the Administrative Procedure Act (APA). In addition, BOEM has failed to recognize the tremendous burden the changes being contemplated will have on the offshore oil and natural gas and surety industries. One company estimates that the proposed changes could increase their compliance costs by up to \$20 million annually. We believe that under Executive Order 12866, any NTL including the proposed criteria would be an "economically significant regulatory action" that the Office of Information and Regulatory Affairs (OIRA) is required to review and that BOEM must provide OIRA with an assessment of benefits, costs, and alternatives. Also, given the potential that BOEM's implementation of the criteria could disrupt current production levels should lessees fail to timely comply with the new BOEM guidance, under Executive Order 13211, any NTL containing the criteria could be considered a "significant energy action," therefore triggering BOEM's obligation to also provide OIRA with a statement regarding adverse effects on energy supply and alternatives.

The DOI's Office of Natural Resource Revenue has also published a proposed Royalty Valuation Rule entitled "Consolidated Federal Oil & Gas and Federal &

Indian Coal Valuation Reform” which redefines “gathering” for offshore operations. The new definition reverses historical treatment of all subsea movement of bulk production as “transportation” (an allowable deduction) and now considers it “gathering” (not an allowable deduction), ignoring relevant facts such as the long distances traveled and the relative paucity of deepwater surface facilities. It could potentially promote more deepwater structures at significant wasted cost and accompanying risk.

CONCLUSION

Safety is a core value for the oil and natural gas industry. We are committed to safe operations and support effective regulations related to offshore oil and natural gas exploration and production, working together we can develop practical final rules that are ultimately both feasible and effective.

Appendix A**SUMMARY OF JITFs****Joint Industry Offshore Operating Procedures Task Force**

The Procedures JITF reviewed critical processes associated with drilling and completing deepwater wells to identify gaps between existing practices and regulations and Industry best practices. Their recommendations focused on the following five areas: cementing; loads and resistance; fluid displacement and negative testing; abandonment and barriers; and safety case. Their recommendations were intended to move Industry standards to a higher level of safety and operational performance and resulted in either revision or new development of API guidelines, which are considered Industry best practices for global oil and gas operations.

Joint Industry Offshore Equipment Taskforce

The Equipment JITF reviewed current BOP equipment designs, testing protocols and documentation. Their recommendations were designed to close any gaps or capture improvements in these areas and focused on: safety case regime; a robust management of change (MOC) process; accessing shear data; remotely operated vehicle (ROV) interface; and acoustic reliability. After submitting its recommendations, the Equipment JITF formed three subgroups to evaluate information regarding BOP shearing capabilities, BOP acoustics systems, and BOP/ROV interface. These subgroups each produced white papers regarding their topics in January of 2011.

Joint Industry Subsea Well Control and Containment Task Force

The Subsea JITF reviewed technologies and practices for controlling the release of oil from the source of a subsea well where there has been a loss of control. These include equipment designs, testing protocols, research and development (R&D), regulations and documentation to determine if enhancements were needed. The JITF identified five key areas of focus for GOM deepwater operations:

- Well containment at the seafloor;
- Intervention and containment within the subsea well;
- Subsea collection and surface processing and storage;
- Continuing R&D; and
- Relief wells.

The Subsea JITF focused primarily on potential operational scenarios after a well blowout has occurred. Consideration was also given to containment of hydrocarbons that may leak from subsea production system equipment (e.g. subsea production well) and casing stubs at the seafloor. The task force did not review blowout preventers (BOPs), Emergency Disconnect Systems (EDS), autoshear systems, deadman systems, or ROV/BOP interfaces (pumps and hot stab). These items were reviewed under the Equipment JITF.

The Subsea JITF developed 29 recommendations on specific steps to enhance the Industry's subsea control and containment capability, including 15 immediate action items.

One of the first recommendations implemented was to provide near-term response capability for well containment. This was achieved through the establishment of collaborative containment companies such as Marine Well Containment Company (MWCC) and HWCG, LLC founded in 2010 to provide containment technology and response for the unique challenges of capping a well. These companies develop and operate quickly deployed systems that are able to stem the uncontrolled flow from a well either by sealing it or directing it into storage vessels on the surface. More information on these companies can be found at <http://www.marinewellcontainment.com> and <http://www.hwcg.org>.

Joint Industry Oil Spill Preparedness and Response Task Force

<http://oilspillprevention.org/oil-spill-research-and-development-cente>

The OSPR JITF was formed to review the industry's ability and capacity to respond to an oil spill of national significance. The task force addressed both the preparedness for response and the actual response to crude oil or related oil products after they have escaped containment during Exploration & Production activities and entered into the surrounding environments (e.g. sub-sea, surface, shoreline, etc.).

Following the September 3, 2010, OSPR JITF preliminary recommendations report, the API Oil Spill Preparedness and Response Subcommittee (OSPRS) convened to address the recommendations made by the JITF. The OSPRS was tasked with leading Industry efforts to develop and implement plans that

addressed the report recommendations while staying abreast of related initiatives. The OSPRS has maintained and enhanced collaboration with international organizations (e.g., International Association of Oil and Gas Producers-Global Industry Response Group (IOGP-GIRG) and the Arctic Response Technology Joint Industry Program (JIP)), well containment companies, Oil Spill Response Organizations (OSROs), and academic institutions such as Coastal Response Research Center (CRRC) and the Gulf of Mexico Research Initiative (GOMRI). The subcommittee also reviewed and commented on emerging materials related to oil spill response, such as the Presidential Commission Findings, Incident Specific Preparedness Review, draft NRT subsea dispersant guidance, BOEM/BSEE planning guidance, and a number of scientific reports (e.g., Operational Science Advisory Team Report).

The OSPRS spent several months developing and prioritizing project plans to address each preliminary recommendation, and subsequently received approval and Industry funding commitment for a multi-year work program. The OSPRS divided the recommendations into seven categories, or work streams, as outlined in the original report, specifically:

- Planning
- Dispersants
- Shoreline Protection and Cleanup
- Oil Sensing and Tracking
- In-Situ Burning
- Mechanical Recovery
- Alternative Technologies

Within each category there are a number of projects being worked by individual project teams. These individual project teams are led by a member of the OSPRS. The teams have developed scoping documents and project plans complete with milestones and are in the process of implementation. In some cases projects have endorsed budgets for one or more years to allow access to contractors/consultants or other support services to complete studies, research, workshops, etc.

These projects involved collaboration among Industry, government, and academia. Some project teams are carrying out large-scale research studies while

other teams have assumed a monitoring and engagement role if similar initiatives are being conducted by other entities (such as the Federal government).

API and the oil and natural gas industry have established a robust oil spill response research and development program that oversees more than 25 projects in the eight areas previously outlined (planning, mechanical recovery, dispersants, in situ burning, remote sensing, shoreline protection, alternative technologies). While a great deal of attention continues to be given to offshore incidents, further focus is also being directed towards near-shore and inland spill response, and industry continues to engage with Federal stakeholders, science and the academic community on these areas of focus.

Based on the assessment conducted immediately after the Macondo incident, a number of publically available reports and guidance documents have also been created, including:

- Spill Response Planning:
 - API Training and Exercise Guidelines
 - Guidelines for Offshore Oil Spill Response Plans
 - Personal Protective Equipment Selection for Oil Spill Responders
 - Net Environmental Benefit Analysis (NEBA) Graphical Briefing
- Oil Sensing & Tracking
- Remote Sensing Planning Guidance
- Dispersants:
 - Dispersants Fact Sheet 1 - Introduction to Dispersants
 - Dispersants Fact Sheet 2 - Dispersants and Human Health and Safety
 - Dispersants Fact Sheet 3 - Fate of Oil and Weathering
 - Dispersants Fact Sheet 4 - Toxicity and Dispersants
 - Dispersants Fact Sheet 5 - Dispersant Use Approvals in the United States
 - Dispersants Fact Sheet 6 - Trade Offs
 - Dispersants Fact Sheet 7 - Aerial Vessel
 - Dispersants Fact Sheet 8 – Subsea and Point Source Dispersant Operations
 - Dispersant Fact Sheet 9 – Dispersant Use & Regulation Timeline
 - Dispersant Fact Sheet 10 – Dispersant Use in the Arctic Environment
 - Industry Recommended Subsea Dispersant Monitoring Plan
 - API JITF Subsea Dispersants Injection Newsletters

- The Role of Dispersants in Oil Spill Response
- SINTEF Dispersants Effectiveness Report – Phase I
- SINTEF Dispersants Effectiveness Report – Phase II
- Aerial and Vessel Dispersant Preparedness and Operations Guide, API Technical Report 1148
- In-Situ Burning
 - Field Operations Guide for In-situ Burning of Inland Oil Spills, API Technical Report 1251
 - Field Operations Guide for In-situ Burning of On-Water Oil Spills, API Technical Report 1252
- Mechanical Recovery
- Deepwater Horizon Mechanical Recovery System Evaluation Technical Report 1143
- Shoreline Protection:
 - Oil Spills in Marshes
 - Subsurface Oil Detection Report
 - Subsurface Oil Detection Field Guide
 - Subsurface Oil Detection and Delineation in Shoreline Sediments Phase 2 — Final Report
 - Shoreline Protection on Sand Beaches (aka Berms and Barriers) Report
 - Shoreline Protection on Sand Beaches (aka Berms and Barriers) Guide
 - Mechanized Cleanup of Sand Beaches Report
 - Tidal Inlet Protection Strategies (TIPS) Report
 - Biodegradation & Bioremediation on Sand Beaches Report
- Alternative Response Technologies
- Evaluation of Alternative Response Technology Evaluation (ARTES) Technical Report 1142
- Educational Media: Dispersants Role in Biodegradation Video; Net Environmental Benefit Analysis Instructional Video; Principles of Oil Spill Prevention and Response Instructional Video
- Spill Prevention YouTube Channel
- OilSpillPrevention.org Website
- Guidance on the creation of offshore oil spill response plans
- An evaluation of the mechanical recovery systems used at sea during the Macondo incident

- A report (and associated field guide) for spills on sand beaches and shoreline sediments, including protection techniques and detection and response capabilities
- An evaluation of the process by which alternative technologies are reviewed for use during an oil spill

The industry has also invested in two international oil spill preparedness and response programs focused on improving industry operational capabilities in all parts of the world including the Arctic. These two programs are coordinated with API's activities, and together, they represent a comprehensive, global approach to continued advancements in oil spill preparedness and response. A newsletter providing periodic updates on these activities can be found at <http://www.api.org/environment-health-and-safety/clean-water/oil-spill-prevention-and-response/api-jitf-subsea-dispersant-injection-newsletter>

The full suite of industry reports and recommendations are available at <http://www.api.org/oil-and-natural-gas-overview/exploration-and-production/offshore/api-joint-industry-task-force-reports>.

PREVENTION: INDUSTRY STANDARDS

Reviewing and improving industry standards has always been a top priority. Since 1924, API has been the leader in developing industry standards that promote reliability and safety through the use of proven engineering practices. The API standards process is accredited by the American National Standards Institute (ANSI), which is the standards authority here in the United States and accredits similar programs at several national laboratories. As part of API's accredited process all API standards are reviewed on a regular basis to ensure they remain current. API standards are developed in an open and transparent process which includes subject matter experts from Academia, Government and Industry and are the most widely cited oil industry standards by Federal, State, and International Regulators.

API has approximately 275 exploration and production standards that address offshore operations, covering everything from blowout preventers to comprehensive guidelines for offshore safety programs, and more than 100 have been incorporated into federal regulation. Since 2010 API has published over 100

new and revised exploration and production standards; key standards include the following:

New Documents:

- RP 96, *Deepwater Well Design and Construction*, 1st Edition, March 2013
In June 2010, an API work team held a kick-off meeting to outline initial content for the new API RP 96. This document provides well design and operational considerations to safely design and construct deepwater wells with maximum reliability. There was coordination with the Subsea JITF and the API Standard 53 workgroup to ensure their recommendations were addressed in the document as well.
- Bulletin 97, *Well Construction Interface Guidelines*, 1st Edition, April 2011
In July 2010, the Procedures JITF held a kick-off meeting to outline initial content for Bulletin 97. Bulletin 97 provides guidance on information that is to be shared regarding well construction and rig-specific operating guidelines. It is intended to align the lease operator's safety and environmental management system (SEMS) with drilling contractor's safe work practices (CSWP). The WCID-SEMS is a bridging document that includes the elements identified in API 75 within the context of well construction activities. It is understood that work processes vary between operators and contractors, which should be honored in the development of the WCID document.
- Specification Q2, *Quality Management System Requirements for Service Supply Organizations for the Petroleum and Natural Gas Industries*, 1st Edition, December 2011
- RP 17W, *Subsea Capping Stacks*, 1st Edition, July 2014
In August 2011 a workgroup was formed to create a new document on subsea capping stack recommended practices for design, manufacture, and use. The document applies to the construction of new subsea capping stacks and can be used to improve existing subsea capping stacks. The document can aid in generating a basis of design (BOD) document as well as preservation, transportation, maintenance, testing documents, and operating instructions.
- TR 17TR8, *High-temperature, High-pressure Design Guidelines*, 1st Edition, February 2015

This technical report is to provide design guidelines for oil and natural gas subsea equipment utilized in high-pressure high-temperature (HPHT) environments.

- RP 17V, Recommended Practice for Analysis, Design, Installation, and Testing of Safety Systems for Subsea Applications, 1st Edition, February 2015
- RP 98, Personal Protective Equipment Selection for Oil Spill Responders, 1st Edition, August 2013

This RP was developed from a recommendation of the OSPRS and provides general information and guidance for the development of oil spill responder personal protective equipment (PPE) control measures. Although an extensive amount of information has been developed on the topic of PPE for emergency responders, this document focuses on the PPE selection process as well as its technical evaluation based on the hazards present.
- TR 1PER15K-1, Protocol for Verification and Validation of High-Pressure and High-Temperature Equipment, 1st Edition, March 2013

This report focuses on an evaluation process for HPHT equipment in the petroleum and natural gas industries which includes design verification analysis, design validation, material selection considerations, and manufacturing process controls necessary to ensure the equipment is fit-for-service in the applicable HPHT environment.
- RP 2SIM, Structural Integrity Management of Fixed Offshore Structures, 1st Edition, June 2013

Revised documents:

- Standard 53, Blowout Prevention Equipment Systems for Drilling Wells, 4th Edition, November 2012

Based on the Equipment task force's recommendations, an API work team began development on the fourth edition of API RP 53. The purpose of the document is to provide requirements on the installation and testing of blowout prevention equipment systems on land and marine drilling rigs (barge, platform, bottom-supported, and floating). The fourth edition was updated to a Standard.
- Standard 65-2, Isolating Potential Flow Zones During Well Construction, 2nd Edition, December 2010

API Recommended Practice (RP) 65—Part 2 was first published in May 2010. API then revised the document based on 1) lessons learned from

the Macondo incident; and 2) alignment with the planned Deepwater Well Design and Construction RP (discussed below). The revisions resulted in the API RP becoming API Standard 65-Part 2, second edition. The document contains best practices for zone isolation in wells to prevent annular pressure and/or flow through or past pressure-containment barriers that are installed and verified during well construction. Well construction practices that may affect barrier sealing performance are mentioned along with methods to help ensure positive effects or to minimize any negative ones.

- RP 17H, Remotely Operated Tools and Interfaces on Subsea Production Systems, 2nd Edition, November 2014
Based on recommendations from the Equipment JITF the first edition of API 17H was revised. The second edition provides recommendations for development and design of remotely operated subsea tools and interfaces on subsea production systems in order to maximize the potential of standardizing equipment and design principles.
- Specification Q1, Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry, 9th Edition, June 2013
- Specification 14A, Subsurface Safety Valve Equipment, 12th Edition, January 2015
- Specification 16C, Choke and Kill Systems, 2nd Edition, March 2015

Standards under development:

- Specification 16A, Specification for Drill-through Equipment , 4th Edition
- Standard 16AR, Repair and Remanufacture of Blowout Prevention Equipment, 1st Edition
- Specification 16D, Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment, 3rd Edition
- Specification 16F, Specification for Marine Drilling Riser Equipment, 2nd Edition
- Recommended Practice 16Q, Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems, 2nd Edition
- Specification 16R, Marine Drilling Riser Couplings, 2nd Edition
- Specification 16RCD, Drill Through Equipment - Rotating Control Devices, 2nd Edition
- Recommended Practice 16ST, Coiled Tubing Well Control Equipment Systems, 2nd

- Recommended Practice 64, Recommended Practice for Diverter Systems Equipment and Operations, 3rd Edition
- Recommended Practice 75, Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities, 4th Edition
- 18 Life Cycle Management, 1st Edition

Government-referenced and safety-related standards may be freely viewed online at <http://publications.api.org>.

SUMMARY

The Macondo incident was a tragedy that cost eleven lives, and as a result, was a call to action to industry to identify and develop multiple improvements in offshore equipment, operations, well design, well control equipment targeted at prevention and containment and new procedures and tools for responding to oil spills. These activities have created a model safety program in the GOM and beyond for well operations crews and the environment. Active participation from and coordination with the public sector, academia, and other stakeholders has been fundamental to turning initial recommendations into genuine plans of action and enhanced safety guidelines. As always, standards and best practices will continue to be reviewed on an ongoing basis in order to protect the environment and promote the safe and responsible development of energy sources that help fuel the American economy.

The oil and natural gas industry and the federal government have together taken great strides to protect workers and the environment and to improve the safety of offshore drilling operations. As the co-chairs of the President's spill commission said in 2014, offshore drilling is safer than it was five years ago. The industry has placed a particular focus on increasing its ability to 1) prevent spills from occurring, 2) intervene to halt any spill that does occur, and 3) respond to spills with the most effective mitigation measures possible.

The industry stands committed to safe and environmentally responsible development.



Improvements to
OFFSHORE SAFETY
BY INDUSTRY AND GOVERNMENT

energy **API** April, 2015

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[INDUSTRY]

JITF Reports

In response to the Gulf of Mexico (GOM) incident, the U.S. oil and natural gas industry launched a comprehensive review of offshore safety.

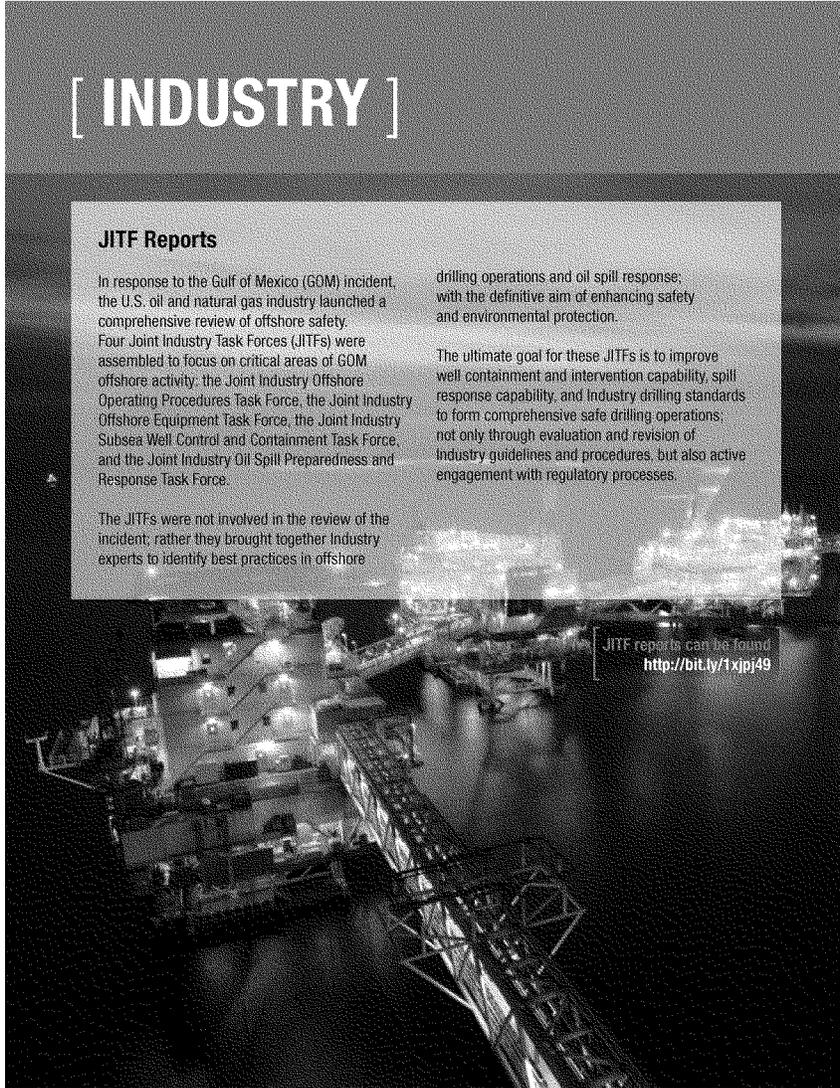
Four Joint Industry Task Forces (JITFs) were assembled to focus on critical areas of GOM offshore activity: the Joint Industry Offshore Operating Procedures Task Force, the Joint Industry Offshore Equipment Task Force, the Joint Industry Subsea Well Control and Containment Task Force, and the Joint Industry Oil Spill Preparedness and Response Task Force.

The JITFs were not involved in the review of the incident; rather they brought together industry experts to identify best practices in offshore

drilling operations and oil spill response; with the definitive aim of enhancing safety and environmental protection.

The ultimate goal for these JITFs is to improve well containment and intervention capability, spill response capability, and industry drilling standards to form comprehensive safe drilling operations; not only through evaluation and revision of industry guidelines and procedures, but also active engagement with regulatory processes.

JITF reports can be found
<http://bit.ly/1xppj49>



[Standards]

API is the world's leading standard-developing organization for the oil and natural gas industry and has developed standards since 1924. API's formal consensus process is accredited by the American National Standards Institute (ANSI), the same institute that accredits similar programs at several U.S. national laboratories. API standards are developed in an open and transparent process and are the most widely cited oil industry standards by Federal, State, and International Regulators. Since 2010 API has published over 100 new and revised exploration and production standards.

Key standards include the following:

New Documents:

- » **RP 96**, Deepwater Well Design and Construction, 1st Edition, Mar. 2013
- » **Bulletin 97**, Well Construction Interface Guidelines, 1st Edition, April 2011
- » **Specification Q2**, Quality Management System Requirements for Service Supply Organizations for the Petroleum and Natural Gas Industries, 1st Edition, Dec. 2011
- » **RP 17W**, Subsea Capping Stacks, 1st Edition, July 2014
- » **TR 17TR8**, High-temperature, High-pressure Design Guidelines, 1st Edition, February 2015
- » **RP 17V**, Recommended Practice for Analysis, Design, Installation, and Testing of Safety Systems for Subsea Applications, 1st Edition, February 2015
- » **RP 98**, Personal Protective Equipment Selection for Oil Spill Responders, 1st Edition, Aug. 2013
- » **TR 1PER15K-1**, Protocol for Verification and Validation of High-Pressure and High-Temperature Equipment, 1st Edition, March 2013
- » **RP 2SIM**, Structural Integrity Management of Fixed Offshore Structures, 1st Edition, June 2013
- » **Specification Q1**, Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry, 9th Edition, June 2013
- » **Specification 14A**, Subsurface Safety Valve Equipment, 12th Edition, January 2015
- » **Specification 16C**, Choke and Kill Systems, 2nd Edition, March 2015

Documents Under Development:

- » **Specification 16A**, Specification for Drill-through Equipment, 4th Edition
- » **Standard 16AR**, Repair and Remanufacture of Blowout Prevention Equipment, 1st Edition
- » **Specification 16D**, Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment, 3rd Edition
- » **Specification 16F**, Specification for Marine Drilling Riser Equipment, 2nd Edition
- » **Recommended Practice 16Q**, Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems, 2nd Edition
- » **Specification 16R**, Marine Drilling Riser Couplings, 2nd Edition
- » **Specification 16RCD**, Drill Through Equipment - Rotating Control Devices, 2nd Edition
- » **Recommended Practice 16ST**, Coiled Tubing Well Control Equipment Systems, 2nd Edition
- » **18 Life Cycle Management**, 1st Edition

Revised Documents:

- » **Standard 53**, Blowout Prevention Equipment Systems for Drilling Wells, 4th Edition, Nov. 2012
- » **Standard 65-2**, Isolating Potential Flow Zones During Well Construction, 2nd Edition, Dec. 2010
- » **RP 17H**, Remotely Operated Tools and Interfaces on Subsea Production Systems, 2nd Edition, November 2014

[Center For Offshore Safety (COS)]

The Center for Offshore Safety (COS) supports and enables continuous understanding and improvement in safety and environmental management systems (SEMS). The work is based on API Recommended Practice 75.

Mission: Promote the highest level of safety for offshore drilling, completions, & operations by effective leadership, communication, teamwork, utilization of disciplined safety management systems & independent third-party auditing & certification.

COS Areas of Activity:

- ▶ SEMS audit tools and audit service provider accreditation
- ▶ SEMS Certification Program for Operators and Contractors
- ▶ Data and learnings collection and analysis of Safety Performance indicators and Learning from Incidents
- ▶ SEMS Good Practice Development
- ▶ COS Safety Events and Programs
- ▶ Decision making at all levels will not compromise safety
- ▶ Safety processes, equipment, training, and technology undergo constant examination and improvement
- ▶ Members will share learnings and embrace industry Standards and best practices, to promote continual improvement
- ▶ Open communication and transparency of safety information is utilized to build mutual trust among stakeholders and promote collective improvement in industry performance

The COS Works to Achieve Operational Excellence by:

- ▶ Enhancing and continuously improving industry's safety and environmental performance
- ▶ Gaining and sustaining public confidence and trust in the oil and gas industry
- ▶ Increasing public awareness of the industry's safety and environmental performance
- ▶ Stimulating cooperation within industry to share best practices and learn from each other
- ▶ Providing a platform for collaboration between industry, the government, and other stakeholders
- ▶ Collaborative approaches are utilized to drive safe and responsible operations
- ▶ Everyone is personally responsible for safety and empowered to take action

Guiding Principles of the COS Include:

- ▶ Industry leaders demonstrate a visible commitment to safety
- ▶ Operators, contractors, and suppliers work together to create a pervasive culture of safety

The Center For Offshore Safety has developed Safety and Environmental Management Systems (SEMS) tool kits, as well as auditor qualification, certification, and accreditation tools.

All of these are available on their website:
<http://www.centerforoffshoresafety.org>



[Subsea Well Intervention Capability]

The Marine Well Containment Company (<http://www.marinewellcontainment.com>) and the HWCG, LLC (<http://www.hwcg.org>) were founded in 2010 to provide containment technology and response capabilities for the unique challenges of capping a well that is releasing oil thousands of feet below the water's surface.

These companies maintain quickly deployable systems that are designed to stem any uncontrolled flow of hydrocarbons from a subsea well and facilitate training of their member companies on the installation and operation of these systems.

These systems also provide the potential to capture flow from a subsea well incident via subsea equipment, risers and containment vessels that can safely capture, store and offload the oil.

MWCC Containment System in a Cap and Flow Scenario

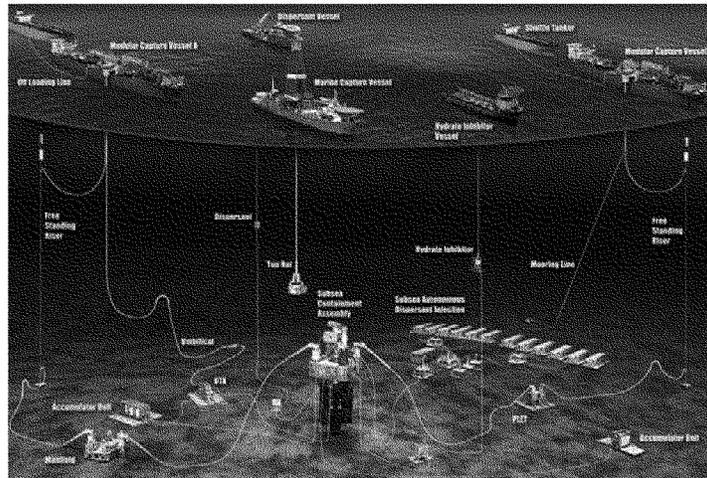


Photo Copyright 2010-2015 Marine Well Containment Company

[Oil Spill Prevention and Response]

<http://www.oilspillprevention.org>

The U.S. oil and natural gas industry is committed to meeting the nation's energy needs while maintaining safe and environmentally sound operations. This requires continuous investment and improvement in every phase of preparedness and operations in which oil is produced, transported, stored, and marketed.

Exploration and production facilities use advanced technologies, materials, and practices, which incorporate multiple back-up safety systems. Pipelines employ computers, electromagnetic instruments, and ultrasonic devices that detect vulnerabilities to enable proactive maintenance and repair. Marine terminal and vessel designs are constantly improved; tankers, for example, are now built with double hulls as an extra measure of security.

Additionally, storage tanks are now constructed with special materials to withstand corrosion. Industry also invests in practices and technologies that ensure a quick and effective response in the event of a spill.

The United States has established one of the world's most sophisticated and well-coordinated spill response networks by bringing together the resources and expertise of private industry, public agencies, and academia to make sure we learn everything we can from past incidents.

[Responders]

RP on Oil Spill Response Plans (In Development)
Oil Spill Response Technical Reports:

- ▶ **Spill Response Planning:**
 - » API Training and Exercise Guidelines
 - » Guidelines for Offshore Oil Spill Response Plans
 - » Personal Protective Equipment Selection for Oil Spill Responders
 - » Net Environmental Benefit Analysis (NEBA) Graphical Briefing

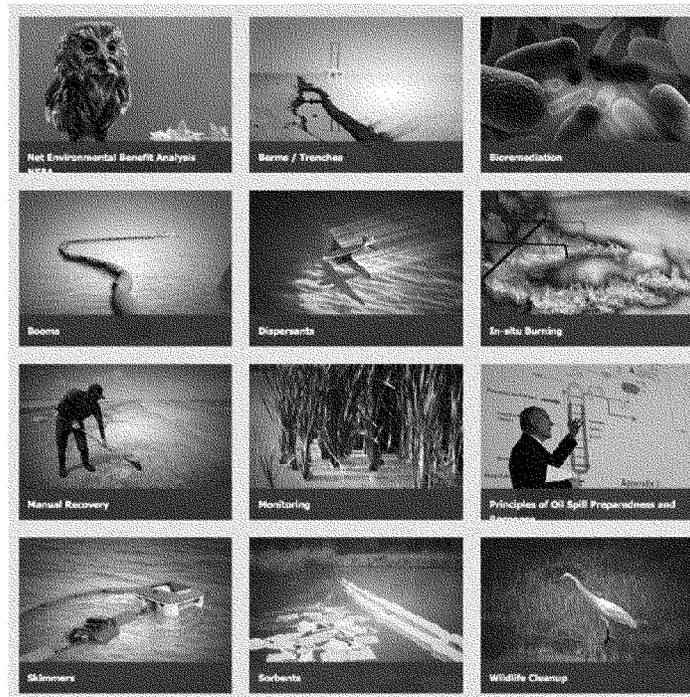
- ▶ Oil Sensing & Tracking
- ▶ Remote Sensing Planning Guidance
- ▶ Mechanical Recovery

[Dispersants]

- » Dispersants Fact Sheet 1--
Introduction to Dispersants
- » Dispersants Fact Sheet 2 --
Dispersants and Human Health and Safety
- » Dispersants Fact Sheet 3 --
Fate of Oil and Weathering
- » Dispersants Fact Sheet 4 --
Toxicity and Dispersants
- » Dispersants Fact Sheet 5 --
Dispersant Use Approvals in the United States
- » Dispersants Fact Sheet 6 --
Trade Offs
- » Dispersants Fact Sheet 7 --
Aerial Vessel
- » Dispersants Fact Sheet 8 --
Subsea and Point Source Dispersant Operations
- » Dispersant Fact Sheet 9 --
Dispersant Use & Regulation Timeline
- » Dispersant Fact Sheet 10 --
Dispersant Use in the Arctic Environment
- » Industry Recommended Subsea -- Dispersant
Monitoring Plans
- » API JITF Subsea Dispersants Injection Newsletters
- » The Role of Dispersants in Oil Spill Response
- » SINTEF Dispersants Effectiveness Report -- Phase I

- ▶ **In-Situ Burning**
 - » Mechanical Recovery
 - » Deepwater Horizon Mechanical Recovery System
Evaluation Technical Report 1143

- ▶ **Shoreline Protection**
 - » Oil Spills in Marshes
 - » Subsurface Oil Detection Report
 - » Subsurface Oil Detection Field Guide
 - » Subsurface Oil Detection and Delineation in Shoreline Sediments Phase 2 — Final Report
 - » Shoreline Protection on Sand Beaches (aka Berms and Barriers) Report
- » Shoreline Protection on Sand Beaches (aka Berms and Barriers) Guide
- » Mechanized Cleanup of Sand Beaches Report
- » Tidal Inlet Protection Strategies (TIPS) Report
- » Biodegradation & Bioremediation on Sand Beaches Report
- ▶ **Alternative Response Technologies**
 - » Evaluation of Alternative Response Technology Evaluation (ARTES) Technical Report 1142



[GOVERNMENT]

The Federal Government

Responded to the Macondo incident by reorganizing the Minerals Management Service (MMS) and focusing on four areas of regulatory policy: **1)** blowout prevention, **2)** drilling safety, **3)** spill response and **4)** well containment. To help accomplish this, the MMS was reorganized into three new agencies:

- The Bureau of Ocean Energy Management (BOEM), responsible for energy leases in areas of the U.S. Outer Continental Shelf;
 - The Bureau of Safety and Environmental Enforcement (BSEE), responsible for enforcement of safety and environmental protection in all offshore energy activities, and;
 - The Office of Natural Resources Revenue (ONRR), responsible for management of royalties and revenues.
- These new agencies identified areas for improvement through a series of regulatory and policy actions, including:

The Bureau of Ocean
Energy Management
<http://www.boem.gov>

The Bureau of Safety
and Environmental
Enforcement
<http://www.bsee.gov>

The Office of Natural
Resources Revenue
<http://www.onrr.gov>

[Regulations & Notices to Lessees and Operators (NTLs)]

- ▶ Issued NTL No. 2010-N06, Information Requirements for Exploration Plans, Development and Production Plans, and Development Operations Coordination Documents on the OCS June 18, 2010, provided FAQs July 15, 21 and August 10
- ▶ BOEMRE published an Interim Final Drilling Safety Rule October 14, 2010
- ▶ BOEMRE published a Final Safety and Environmental Safety Systems Rule October 15, 2010
- ▶ BOEMRE issued NTL No. 2010-N10, Statement of Compliance with Applicable Regulations and Evaluations of Information Demonstrating Adequate Spill Response and Well Containment Resources on November 8, 2010
- ▶ Published the Final Drilling Safety Rule August 2012
- ▶ Published the Final SEMS II Rule April 2013
- ▶ Published Safety Culture Policy Statement May 2013
- ▶ Published Proposed Production Safety Systems Rule August 2013
- ▶ Published Proposed Aviation Regulations November 2014
- ▶ Published Proposed Arctic Regulations February 2015
- ▶ Proposed Well Control Rule April 2015
- ▶ Specific approvals needed for change-out to lighter weight fluids and negative test procedures
 - » Blowout Preventer (BOP) and Control Systems
 - ▶ New blind-shear ram function testing and 3rd Party verification required
 - ▶ New requirements & function testing for auto shear & deadman systems
 - ▶ Minimum requirements and testing for ROV intervention established
 - ▶ BOP inspection & maintenance to API RP 53 required
 - ▶ Minimum requirements established for personnel operating BOP equipment
- ▶ Worst Case Blowout Discharge (WCD) & Blowout Response (NTL-2010-N06) policies were established.
 - » New requirements and definitions for WCD calculations
 - » New requirements for describing intervention & relief well drilling constraints
- ▶ Demonstration of adequate spill response capability and well containment resources (NTL-2010-N10) were required.
 - » Signed statement of compliance required
 - » Well Containment Screening Tool developed to demonstrate that well design withstand being capped or captured
 - » Well Containment Plan required (usually including a contract for the services of a Well Containment Company)
 - » Must demonstrate access to equipment & staff resources to deploy containment prior to drilling a well

Some of the Detailed Requirements From the Above:

- ▶ Drilling Safety Rules (Interim Final Rule)
 - » Well Integrity
 - ▶ Isolating Potential Flow Zones (Use of API RP 65-2 became mandatory)
 - ▶ Well design (casing and cement program) must be certified by Professional Engineer (PE)
 - ▶ Two Independent Barriers (certified by PE) during completion activities
 - ▶ Procedures for installation, sealing, and locking of casing hangers required
- ▶ Safety and Environmental Management Systems regulations were strengthened.
 - » All elements of API RP 75 Safety and Environmental Management System (SEMS) were made mandatory
 - » SEMS audits and reporting are now required
 - » Operators are now responsible for verification of Contractors SEMS
 - » As of June 2015 SEMS must be audited by an accredited audit service provider (ASP)

U.S. Coast Guard (USCG) Actions Post Macondo

- ▶ Published new Marine Casualty Reporting forms and a proposed rule on Marine Casualty Reporting.
- ▶ Published proposed revisions to Crane Regulations.
- ▶ Published voluntary guidance for compliance by US-flag vessels with MARPOL Annex VI International Energy Efficiency (IEE) requirements. Proposed regulations expected.
- ▶ Published a final rule amending Vessel Inspection Alternatives regulations to add the International Energy Efficiency (IEE) Certificate to the list of certificates that a recognized classification society may issue on behalf of the Coast Guard.
- ▶ Published final regulations for 3rd-party testing & certification of electrical equipment in hazardous locations on newly constructed MODUs, floating OCS facilities, and vessels other than offshore supply vessels (OSVs) that engage in OCS activities.
- ▶ Published Interim Voluntary Mobile Offshore Drilling Unit (MODU) Dynamic Positioning (DP) Guidance for DP system guidance and recommended DP incident reporting criteria.
- ▶ USCG issued Safety Alert #08-14 jointly with BSEE's SA 312 on Dynamic Positioning System Failures on Vessels Other Than Mobile Offshore Drilling Units (Vessels).
- ▶ Published a proposed rule establishing minimum design, operation, training, and manning standards for mobile offshore drilling units (MODUs) and other vessels using DP systems to engage in Outer Continental Shelf (OCS) activities.
- ▶ Published a proposed rule amending rules relating to production testing of lifesaving equipment and harmonization with international standards.
- ▶ Published Interim Voluntary Guidance on Lifesaving and Fire-Fighting Equipment, Training and drills onboard manned offshore facilities and MODUS on the OCS.
- ▶ Published a proposed rule on Harmonization of Standards for Fire Protection, Detection, and Extinguishing Equipment.
- ▶ Published a policy letter establishing Alternate Design and Equipment Standard for Floating Offshore Installations (FOI) and Floating Production, Storage, and Offloading (FPSO) Units on the U.S. Outer Continental Shelf.
- ▶ Published an advanced notice of proposed rulemaking on regulations that will require certain vessels operating on the OCS to develop, implement and maintain a Safety Management System.
- ▶ BSEE and the USCG announced a new MOA to strengthen the working relationship between their two agencies on the management of safety and environmental protection responsibilities on the OCS. The new MOA was effective on April 30, 2013.
- ▶ Published draft revisions to the Marine Safety Manual (MSM, Volume III, Chapters 20-26 Marine Industry Personnel).
- ▶ BSEE and the USCG signed a MOA for regulating MODUs on the OCS. Through this agreement, both BSEE and the USCG will work together to identify and coordinate responsibilities for the inspection and oversight of MODUs.
- ▶ The Coast Guard has encouraged drilling contractors and Flag Administrations who employ foreign vessels in GOM to provide marine crews for their MODUs consistent with the interpretation in Appendix I to USCG Deepwater Horizon investigation.
- ▶ The USCG upgraded its OCS training by sending Offshore Inspectors to training for MODUs and production units at the ABS Academy, taking advantage of similar industry provided training, and working with BSEE to send Coast Guard Offshore Inspectors to some of their training programs.
- ▶ The USCG is planning to establish a single Officer in Charge, Marine Inspection (OCMI) to oversee marine inspection activity for all MODUS and floating OCS facilities (such as FSUs) engaged directly in, capable of engaging directly in, or being constructed to engage directly in oil and gas exploration or production in offshore waters of the Eighth Coast Guard District.

- ▶ Published a final rule on nontank vessel response plans and other response plan requirements.
 - ▶ Issued an ALCOAST related to cyber security and the Marine Transportation System.
 - ▶ Published proposed changes to its maritime safety training requirements to cover all persons other than crew working on offshore supply vessels (OSVs) and mobile offshore units (MOUs) engaged in activities on the U.S. Outer Continental Shelf (OCS), regardless of flag.
 - ▶ Published interim voluntary guidelines concerning fire and explosion analyses for MODUs and manned fixed and floating offshore facilities engaged in activities on the U.S. OCS.
 - ▶ Published an Interim Rule regarding Offshore Supply Vessels of at Least 6,000 GT ITC to ensure the safe carriage of oil, hazardous substances, and individuals other than crew by requiring U.S.-flagged OSVs of at least 6,000 gross tonnage as measured under the Convention Measurement System to comply with existing regulatory requirements and international standards for design, engineering, construction, operations and manning, inspections, and certification.
 - ▶ Proposed to increase the limits of liability for vessels, deepwater ports, and onshore facilities, under the Oil Pollution Act of 1990, as amended (OPA 90), to reflect significant increases in the Consumer Price Index (CPI).
 - ▶ Solicited comments on a policy to help vessel and facility operators identify and address cyber-related vulnerabilities that could contribute to a Transportation Security Incident.
 - ▶ Developing revisions to Subpart N Regulations which covers the safety and security of MODUs, floating and fixed facilities on the OCS.
 - ▶ National Offshore Safety Advisory Committee (NOSAC) <https://homeport.uscg.mil/nosac>
 - ▶ The USCG has a Federal Advisory Committee, tasked by the Secretary of Homeland Security to provide recommendations and advice on all matters and actions concerning activities directly involved with or in support of the exploration of offshore mineral and energy resources insofar as they relate to matters within U.S. Coast Guard jurisdiction. This advice also assists the Coast Guard in formulating the position of the United States regarding the offshore industry in advance of International Maritime Organization meetings.
- ▶ NOSAC Completed Reports since 2010:
 - » Dynamic Positioning Operational and Installation Guidelines – Final report submitted February 9, 2011
 - » Dynamic Positioning Operating Personnel Final Report – Final report submitted November 8, 2012
 - » Certification and Standards for Large OSVs – Final report submitted May 19, 2011
 - » Mississippi Canyon Incident Reports Review – Final Report submitted November 8, 2012
 - » Accommodation service vessels engaged in OCS activities – Final report submitted November 14, 2013
 - » Electrical Equipment Certification in Haz Locations on FF MODUs – Final Report submitted November 14, 2013
 - » Additional Lifesaving and Fire Fighting Requirements on the OCS – Final Report submitted November 14, 2013
 - » Safety Impact of Liftboat Sea Service Limitations – Final Report submitted November 14, 2013
 - » Review of Coast Guard Marine Casualty Reporting – Final Report submitted November 14, 2013
 - » Safety Management Systems for Vessels operating on the OCS – Final Report submitted April 17, 2014
 - » Marine Casualty Reporting on the OCS – Final report submitted September 20, 2014
 - » OSV Purpose and Offshore Workers – Final report submitted November 19, 2014
 - » Training and Manning on MOUs and OSVs Operating on the OCS – Final report submitted November 19, 2014
 - » Commercial Diving Safety on the OCS – Final Report submitted April 8, 2015



Additional Government Resources

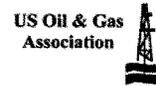
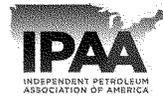
<p>Ocean Energy Safety Institute (OESI) BSEE Fact Sheets: http://1.usa.gov/1NDr1kM OESI Website: http://oesi.famu.edu/</p>	<p>BOEM Changes in Lease Terms for Deepwater Leases http://1.usa.gov/1NDsXcZ</p>
<p>BSEE Confidential Near - Miss Reporting System http://1.usa.gov/1NDrxvZ</p>	<p>BOEM Publishes Proposed Adjustment to Limit of Liability for Offshore Facilities http://www.boem.gov/press/2212014</p>
<p>BSEE National Offshore Training Program http://1.usa.gov/1NDrR0G</p>	<p>BOEM Limiting Use of Categorical Exclusions in NEPA Work http://on.doi.gov/1ND11G</p>
<p>BSEE Technology Center http://1.usa.gov/1NDspaz</p>	<p>BOEM Updated Guidance on Protection of Archeological Sites http://1.usa.gov/1NDtagj</p>
	<p>Minimum Bid For Deepwater Acres http://on.doi.gov/1N0thb</p>



AMERICAN PETROLEUM INSTITUTE



OFFSHORE OPERATORS COMMITTEE



July 16, 2015

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, 1014-AA11*

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 changes to Blowout Prevention Systems and Well Control requirements in 30 C.F.R. part 250. The Bureau of Safety and Environmental Enforcement (BSEE) announced these proposed changes on April 17, 2015, in a notice of proposed rulemaking entitled, "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control."

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. Additionally, many of our associations' members are involved in drilling, equipment manufacturing, construction, and support services for the offshore oil and natural gas industry and all will be adversely impacted by this BSEE rulemaking.

Our members recognize that offshore operations must be conducted safely and in a manner that protects the environment. The U.S. offshore industry has advanced the energy security of our nation, and contributed significantly to our nation's economy. Our goal is for operations integrity and fit-for-risk designs, and we are concerned that many of the requirements in the proposed rule would increase environmental and safety risk in drilling operations rather than improve safety. In addition, we are concerned that the proposed rule would materially impair the ability to maintain current production operations, reduce future development and production or result in taking of leases and stranding of valuable reserves. To avoid these negative unintended consequences it is imperative that BSEE and industry collaborate to develop rules that are more workable and effective.

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.

In developing this response, industry drew on the expertise of eight workgroups comprised of over 300 subject matter experts from more than 70 companies and tens of thousands of man hours. Industry is providing this technically-based set of comments to aid BSEE in its efforts to create a robust and effective well control rule. As stated in our earlier comment letters, we believe additional time to review and comment on this lengthy and complex rulemaking was needed and, had it been provided, would have further contributed to the proposal's development. Indeed, additional time to review and comment on this complicated and lengthy rulemaking is warranted and needed to provide the public an adequate opportunity to participate as required under the Administrative Procedure Act. Going forward substantial industry-regulator engagement is imperative to generate and implement a workable and effective set of rules.

This letter highlights some of the proposed requirements that will have the greatest impact on industry, but there are numerous other specific proposed requirements that will also have significant impacts. Attachment A includes detailed information on how we believe these proposed regulations will significantly impact industry.

General Comments and Themes

Offshore drilling safety depends upon effective risk management. Since the release of the *Deepwater Horizon Investigation*, both the government and industry have implemented broad and extensive measures to improve the safety of offshore drilling operations and enhance worker safety and environmental protection. These measures represent far reaching improvements in standards, regulations and operations addressing safety and environmental management systems, offshore equipment, well design, and well control equipment targeted at prevention and containment and have established new procedures and tools for responding to oil spills.

The current proposed rule does not take these improvements into account and instead establishes prescriptive new requirements that would impose unjustified economic burdens discouraging economic growth, innovation, competitiveness and job creation contrary to Executive Order 13563. In many cases, these requirements are either impracticable or are ill-advised and in some cases would introduce new risk rather than reduce risk. In addition, the proposed rules create a number of undesired side effects which have not been accounted for in the Regulatory Impact Analysis. It is critical that all potential impacts are understood before such significant changes are introduced. Similar to the Initial Regulatory Impact Analysis (RIA) produced by BSEE on the Drilling Safety Rule and the Safety and Environmental Management System (SEMS) rules, the *Initial Regulatory Impact Analysis RIN: 1014-AA11*, published April 03, 2015, significantly underestimates impacts and overstates benefits. The justification provided in the preamble is neither clear nor understood by us.

The proposed rule is significant in both the scope of its requirements, as well as its overall impact. It imposes significant new requirements beyond global industry standards related to well design, well control, casing, cementing, real-time well monitoring, and subsea containment. In addition, the rulemaking not only incorporates guidance from several Notices to Lessees and Operators (NTLs) and industry standards, but also significantly revises provisions related to drilling, workover, completion, and decommissioning operations. The proposed rule impacts and unjustifiably impairs existing facilities and operations as well as facilities currently under development or construction and future operations.

Industry believes that many provisions of the proposed rule also lack articulated rationale. For instance, the discussion on proposed safe drilling margins states that BSEE wants to better define these margins. However, the proposed rule does not discuss how the current requirements are insufficient, how the new requirements were determined, or how these requirements would improve offshore drilling safety. The preamble refers to a recommendation from the *Deepwater Horizon Investigation*, but does not identify the specific recommendation nor explain its relevance to the proposed requirements. In effect, BSEE proposes mitigation, with no supporting rationale, for something that has not been identified as a problem. Not only does this make the proposed rule arbitrary, it also gives industry limited ability to develop or propose alternative strategies or technologies.

A consistent theme noted in the proposed regulation is for BSEE to take an increased role in day-to-day operations and critical decision-making processes. All decisions related to active offshore operations involve accepting a certain level of risk, responsibility and accountability. In the event BSEE seeks to increase its direct or indirect involvement in active drilling operations, further clarification is required on the associated responsibility, accountability and liability that BSEE would assume if an incident occurs as a direct result of those actions.

We request that BSEE arrange workshops with each of the eight industry workgroups that have analyzed respective sections of the proposed rule in order to reach mutual understanding of the proposal, to correct fundamental flaws in the proposed rule, and allow constructive development of rules that are ultimately both workable and effective. We further request that the comment period be reopened during the workshops and that the presentations and discussion be part of the official record.

Well Design (Safe Drilling Margin)

The proposed arbitrary changes to the safe drilling margin and lost circulation requirements will have significant practical and economic consequences in the design and construction of both shelf and deepwater wells. To evaluate the potential effect of the proposed safe drilling margin requirements, industry assessed the impact using a sample of 175 OCS wells drilled since June 2010. It is important to note that all 175 wells were completed under the existing regulations in a safe manner without significant well control incidents. Under the proposed regulations, 63% of the sample wells could not have been drilled as originally designed, as these wells required drilling margins less than the proposed one-half pound per gallon drilling margin or had lost returns.

The current risk-based approach to managing drilling margin (in combination with existing regulatory oversight) has been demonstrated to safely and economically drill wells having narrower drilling margins than the margins that would be allowed by the proposed rule. Production from the resulting wells benefits all stakeholders by providing royalty payments to the U.S. Treasury, supporting U.S. commerce, and reducing reliance on foreign oil imports.

The unintended consequences of the proposed rule will include significant economic and operational hurdles due to increased casing requirements, and smaller production casing sizes resulting in reduced rates or non-commercial production. Evaluation capabilities may also be impacted due to smaller hole sizes. Some new prospects and infill drilling programs will become un-drillable with infeasible prescriptive drilling margin requirements, while others will become cost and resource challenged and, as a result, potentially uneconomic. An offshore lease, however, provides operators valuable contractual and property interests in a purchased lease, *see, e.g., Mobil Oil Exp. & Producing Se., Inc. v. United States*, 530 U.S. 604, 607–08 (2000); *Union Oil Co. of Cal. v. Morton*, 512 F.2d 743, 747 (9th Cir. 1975), and the Government materially breaches a lease when it substantially impairs the value of a lease by imposing new procedures that were not bargained for under the lease and prevent a lessee from exploiting its lease, *see Amber Res. Co. v. United States*, 68 Fed. Cl. 535 (2005); *Amber Res. Co. v. United States*, 73 Fed. Cl. 738 (2006), *aff'd* 538 F.3d 1358 (Fed. Cir. 2008). Further, an arbitrary, prescriptive safe drilling margin based only on mud weight and leak off test criteria may actually reduce the safety of drilling operations as the operator may not be able to choose the mud density best suited for the interval based on drilling and geological parameters. A lower mud weight may have to be used to meet the proposed requirement. The resulting reduction of the mud weight overbalance to the formation could create wellbore stability problems or potentially allow undesired influx of formation fluid into the wellbore. This adds unnecessary downhole drilling risk to the well construction process, possibly impacting personnel, environment and facilities.

Many Exploration Plans (EPs) and Development Operations Coordination Documents (DOCDs), especially in deepwater, include wells that will require drilling through depleted zones or other narrow margin conditions that are allowed under current regulatory protocols. The inability to drill these wells as a result of the prescriptive arbitrary drilling margin set in the proposed rule has the potential to harm project economics and reduce drilling and production on what could be multi-billion dollar developments. For projects on the cusp of approval, delays and cancellations should be expected. Given that hundreds of wells have been successfully and safely drilled with

drilling margins smaller than would be allowable under the proposed rule, it is not clear what problem the rule is trying to solve.

The impact of the proposed rule on continued development and deployment of technologies such as managed pressure drilling technology, dual gradient drilling technology and riser pump systems would be detrimental. These technologies are deployed in narrow drilling margin environments to allow operators to effectively manage these drilling conditions. Such technologies and practices are already common place around the world and can improve drilling safety margins. Overly prescriptive regulations that do not allow for the use of these technologies provide a disincentive to develop them. If these regulations are imposed in the U.S., they will create a competitive disadvantage to OCS lease holders as compared to the rest of the world.

Through well-established operational procedures, hundreds of wells with margins smaller than that required in the proposed rule have been drilled successfully and safely. API Bulletin 92L *Drilling Ahead Safely with Lost Circulation in the Gulf of Mexico* (API 92L) summarizes best drilling practices when drilling wells with narrow drilling margins. API 92L addresses BSEE's concern to document and codify safe drilling margin practices and reduces the need for more prescriptive drilling margin requirements. Therefore, this document should be incorporated by reference into the final rule, in lieu of more stringent drilling margin regulations, for operations where equivalent site-specific lost returns procedures have not been developed.

In summary, a large proportion of the wells drilled in OCS waters will be directly impacted by the proposed drilling margin requirements. Many of the deep wells or wells with depleted zones drilled in OCS waters do not have additional casing options which will negatively affect well completions or, as described above, render wells un-drillable. In addition, new technologies being developed may no longer be available, rendering OCS lease holders uncompetitive. Industry, with input from BSEE, developed API 92L as a guide to safely address lost circulation and low drilling margins. It is an alternative to more prescriptive regulations.

BOP Equipment

There are several important items with respect to BOP equipment. Most notably is the overly prescriptive language on certain requirements, such as: accumulator sizing; testing; BOP configurations; providing access to facilities; Quality Assurance/Quality Control (QA/QC); and oversight imposed on the lessee.

Infeasible implementation timeline

Numerous provisions of the proposed rule are predicated on the availability of BSEE-approved verification organizations (BAVOs) to perform verification and/or certification services in advance of the submission of an application for permit to drill (APD) or application for permit to modify (APM) or a regulatory deadline. There is no guarantee that such services will be available. Even if available, the proposed implementation dates do not allow for a reasonable period of time between the initial approval of a BAVO and the effective date of the provisions of the rule requiring the use of the BAVOs' services. If BAVO provisions are retained in the proposed rule, then there needs to be a reasonable implementation schedule to not interrupt current and planned drilling and production operations.

Except as specified otherwise, BSEE has proposed an effective date of three months following the publication of the final rule. This presents the following difficulties:

- As noted above, BAVOs cannot be “approved” until after the effective date of the rule. Any provision of the rule that requires action by a BAVO cannot be complied with until the BAVO has been approved. Therefore, in order to provide the certification required by proposed § 250.731(c) and (d), there will be considerable delay between the effective date of the rule and the date at which it will be possible to submit an APD or APM. This has the potential to place an effective moratorium on OCS drilling.
- Most existing surface stacks are not equipped with hydraulically operated locking devices. Compliance with the proposed § 250.735(g) would require time to complete the up-front engineering services (including design and qualification testing) and upgrade of the stacks and control systems prior to the date where such stacks must be identified in an APD or APM.
- Given the other demands the proposed rule will place on equipment manufacturers, industry considers three years as a minimum more feasible timeline for implementation of this requirement.

Imposition of requirements beyond those addressed in API 53

The proposed requirements that exceed the provisions of API Standard 53 (API 53), *Blowout Prevention Equipment Systems for Drilling Wells* are unnecessary and will not improve safety. Specifically, the requirements are problematic as follows:

- Implementation of the rule as proposed would require many more accumulators to satisfy larger volumetric requirements leading to larger and heavier BOP stacks than are presently in use. Heavier stacks will result in unintended negative consequences related to their handling, deployment and operation which will impact well construction and design and impose limitations to re-entry into existing wells.
- Many mobile offshore drilling units (MODUs) do not have available space to install the prescribed additional surface BOP accumulator bottles that would be required. In all cases, the additional required associated equipment (e.g., larger fluid reservoir, additional pumps, additional accumulator bottles, etc.) would be problematic in their demands for space and contribution to additional complexity of rig systems. The need for such equipment has not been justified.
- Unnecessarily large accumulator capacities may not be practical and could necessitate removal of other BOP well control components, thereby reducing redundancy and well control options for many vessels.
- Expanded subsea testing of the Deadman/Autoshear beyond current practices and what is defined in API 53 could increase risk of harm to personnel, negatively impact the environment and cause unrecoverable damage to the rig or well. Every time the device must be operated for testing, this increases the risk of limiting the vessel’s capability to actually disconnect, on some systems, in order to meet the proposed requirement both pods are powered down and at that point the vessel is exposed to drift/drive off damage. It is important to inspect, maintain and verify operation and this should be done at intervals designed to best manage risk, as defined in API 53.

Restrictive language on the configuration for the installation of blind-shear rams could lead to loss of additional pipe rams in order to accommodate the prescriptive requirements of the proposed rule. A risk assessment should be conducted and is the correct tool to determine the placement of all rams.

The requirement in the proposed rule for the lessee to ensure that BSEE has access to any facility and to provide prior notification of any shear testing is not feasible absent a significant revision to the placement of regulatory responsibility within 30 CFR Part 250. As presently written, "You" as defined in the rule applies to the lessee. The lessee is not always aware of research and development activities being performed by individual companies or manufacturers.

Similarly, requirements within the proposed rule relating to QA/QC oversight by the lessee are infeasible because the vast majority of designs, manufacturing and testing are completed before a contract is concluded between the purchaser of the equipment (e.g., a drilling or well servicing contractor) and the lessee.

Real Time Monitoring (RTM)

Rulemaking on RTM is premature. BSEE has contracted the Transportation Research Board of the National Academies to advise the agency on the use of real-time monitoring systems by industry and government. Their objective is to determine what measures could reduce the safety and environmental risks of offshore oil and natural gas operations and to make a recommendation on whether RTM should be incorporated into BSEE's regulatory scheme. The final report of the Transportation Research Board should be fully considered by BSEE and the public before any rulemaking on RTM is finalized.

The proposed rule may be interpreted to suggest that BSEE wishes to shift operational decision-making away from rig site personnel to shore. Shifting decision-making away from the offshore personnel should not be the intent of the RTM provisions in the rule as this exposes the operations to increased risk levels. In times where situational awareness is extremely important and immediate action is required, if not integrated into the operations, Remote RTM can become a distraction or, in extreme cases, create an environment of complacency or confusion over accountability. During any given operation, the personnel on the rig offshore have the best understanding and most complete picture of the current operation, key risks, and critical considerations. In addition, their experience in active operations provides them with the judgment to make effective real-time decisions within the bounds specified by the operators' governing procedures and operations integrity guidelines. This authority includes full control of the operations and the full authority to stop activities at any time.

Generally, operators that use shore-based operations centers do so to assist personnel on the rig with the monitoring of specific functions of the drilling operation, not to assume control of operational activities. Operators must retain the flexibility to develop a performance-based approach (rather than follow a prescriptive requirement) described in a Real Time Monitoring Plan similar to the safety and environmental management system (SEMS) program under 30 CFR 250.1900 or the training plan under 30 CFR 250.1500. The Real Time Monitoring Plan should describe what functions of these systems will be monitored in the well(s), which will vary with the rig and its equipment, as well as the location of any support facilities onshore.

Industry would develop a guide to describe the content of a Monitoring Plan. The Monitoring Plan would describe the qualifications of the personnel at the onshore monitoring location and the established protocols that would define when and to whom internal notifications are made when communications outages occur. It should be clear to BSEE that it remains the primary responsibility of the rig-based personnel to monitor information from drilling operations on a 24/7 basis and to take appropriate actions without waiting for direction from a remote shore base.

Inappropriate use of real-time data centers may lead to an erosion of responsibility and accountability of offshore personnel which is critical to maintaining safe operations and responding to emergency situations. In times of communication interruptions or significant offshore events (well control, station keeping difficulties, vessel collisions, equipment failure, etc.) there can be no guarantee of sufficient time to interact with shore base support centers to plan a response. It is during such critical moments that offshore supervision is key, and its effectiveness can only be maintained if the primary decision-making remains focused at offshore locations where situational awareness is crucial. To ensure offshore personnel are equipped with the necessary knowledge prior to specific operations, industry practice is for a range of preparatory engagements to be held with the shore base engineering and operations support teams or through on-site engineering assistance. In these engagements, the key risks and critical steps are discussed to prepare the offshore team for the upcoming operations, including discussion of potential risks, and appropriate responses. This approach should be maintained.

Prior to any rulemaking requiring RTM, serious consideration is required to address cybersecurity concerns when accessing data from operational safety systems (e.g., station keeping, BOP health and status). Opening of data streams to the operational safety systems poses the risk of introduction of viruses or malware. Access from a remote location to any systems on a rig should be fully understood and risk assessed prior to imposition of a regulatory mandate for providing such remote access. Challenges for RTM also include the need for new data transmission protocols and for their adoption throughout industry. This would be a significant change from the current Well Information Transfer Specification (WITS) protocols.

Casing and Cementing

A number of the casing and cementing requirements outlined in the proposed rule are unclear and require design changes that are either not feasible or reduce the chance of safe and successful execution.

For example, proposed § 250.420(c)(2) seeks to increase use of weighted fluids during cementing, without consideration of a number of complications. Increasing mud weight during cement operations increases the risk of lost circulation and may result in failing to attain the required top of cement. Although the higher applied pressure increases the critical gel strength, this pressure is not transmitted through the cement slurry during the slurry's Critical Gel Strength Period. Therefore, additional pressure may be insufficient in the absence of a cement slurry design that properly addresses the Critical Gel Strength Period. The proposed rule may also prohibit the judicious use of un-weighted pre-flushes as a tool for reducing equivalent circulating density (ECD) as a means of improving the chance of a successful cement job.

Overall, these complications can be avoided by maintaining the current regulations that reference API Standard 65-2, 2nd Edition. This standard describes method(s) of isolating potential flow zones. Further detailed remarks on the proposed casing and cementing requirements are included in Attachment A, E, F and G.

Incorporation of API Standards by Reference

Since 1924, API has been the leader in developing industry standards that promote reliability and safety through the use of proven engineering practices. Reviewing and improving industry standards has always been a top priority and practice of the Institute. Since 2010, API has published over 100 new or revised exploration and production standards, covering everything from deepwater well design, to casing and cementing, to capping stacks, to blowout preventers.

API appreciates the fact that a number of its standards are proposed for incorporation by reference in the proposed rule. However, there are instances where this does not appropriately reference the standard's edition or is otherwise unclear or out of context. We offer the following comments:

- The incorporation of API RP 2RD *Recommended Practice for Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs)* should be updated to refer to the Second Edition, September 2013.
- Industry fully supports the incorporation of API Standard 53 (API 53), *Blowout Prevention Equipment Systems for Drilling Wells*, Fourth Edition, November 2012 in its entirety. Through the incorporation by reference of API 53, its normative references (e.g., API Specifications 16A, 16C, 16D and API Recommended Practice 17H) also apply (in part or whole) in context, as specified within the Standard.
- If BSEE intended to reference API Specifications 16A, 16C, 16D and API Recommended Practice 17H for purposes other than their relation to API 53, then those purposes should be specifically stated within the rule or removed entirely. If included, the incorporation by reference of ANSI/API Spec. 16A, *Specification for Drill-through Equipment*, ANSI/API Spec. 16C, *Specification for Choke and Kill Systems*, API Spec. 16D, *Specification for Control Systems for Drilling Well control Equipment and Control Systems for Diverter Equipment* and API Recommended Practice 17H – *Remotely Operated Tools and Interfaces on Subsea production Systems* should be revised such that each edition is cited in a manner such that it is applicable to equipment manufactured after the publication date of the standard to prevent existing equipment and facilities that were manufactured and accepted under previous standards from being rendered obsolete. Any additional requirements against a particular edition need to be justified.
- The incorporation of API Specification Q1, *Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry*, should be updated to the ninth edition, published June 2013. Effective Date: June 1, 2014. This edition of API Q1 is significantly different from and is no longer a U.S. national adoption of ISO TS 29001:2010. The eighth edition of API Q1 is no longer available from ANSI.

- The incorporation of ANSI/API Specification 6A/ISO 10423:2009, *Specification for Wellhead and Christmas Tree Equipment*, should be updated to the Twentieth Edition, October 2010, Effective Date: April 1, 2011, plus Errata 1-4 & Addendum 1-3. API Standard 6ACRA, First Edition, June 2015 Specification should also be referenced for completeness.
- The incorporation of ANSI/API Specification 11D1/ISO 14310:2008 (Modified) *Packers and Bridge Plugs*, should be updated to the Third Edition, April 2015. Incorporating the current edition of API 11D1 ensures alignment of supplier/manufacture documentation with the rule.

Containment

Cap and Flow

The proposed requirements related to containment appear to assume that a cap and flow system, in addition to a cap and contain system is required to control a source at the seafloor in the event of a blowout. If the operator's evaluation using the BSEE-endorsed well containment screening tool indicates that a wellbore can sustain a full shut-in without allowing reservoir fluids to broach the seafloor, then cap and flow well design and equipment should not be required in the operator's permit. Cap and flow well design and equipment should be required for permit approval if the wellbore integrity analysis indicates loss of wellbore integrity while performing a full shut-in during an uncontrolled well event.

Shallow Water Containment

In the preamble of the proposed rule, BSEE solicited comments on whether the source control and containment requirements should be applicable to wells drilled in shallow water. Current subsea containment requirements only address deepwater GOM drilling operations using a subsea BOP or surface BOP on a floating facility. The presently required equipment for a source control event may not be suitable for a shallow water response. Shallow water requirements will vary depending on scenario and would utilize different resources such as divers, over shots or other industry equipment available in the area. Any additional requirements for fixed-bottom drilling operations should be addressed through a separate rulemaking process that takes into account the unique risks and work environment in shallow water that utilizes different resources compared to deepwater operations.

The regulation should be less prescriptive, allowing for potential improvements in technology and equipment, thereby improving response.

The Offshore Operators Committee has formed a Shallow Water Source Control Workgroup committed to considering value of shallow water containment guidelines for GOM shallow water operations, any rulemaking on shallow water containment should be deferred until the OOC work is complete.

Seabed Source Control Alternatives

Although 30 CFR § 250.141 provides for the use of alternative procedures and equipment, it is unclear how these would be approved. We recommend the requirements be made less

prescriptive and open to providing functionally equivalent means for source control to allow for technological advancements. The proposed 30 CFR § 250.141 fails to address the issue as there is no explanation of the perceived risk reduction benefit of the enhanced requirement, which is critical to establishing the baseline expectation. Furthermore, the proposed rule fails to establish justification for the enhanced requirement as required by Executive Order 13563.

Free Standing Hybrid Riser (FSHR)

In lieu of prescriptive FSHR monitoring requirements in the proposed regulations, monitoring requirements should be addressed in an operator's Deepwater Operations Plan (DWOP) as approved by BSEE. The DWOP has proven to be a comprehensive and systematic means of managing deepwater production risks.

Inspection and Mechanical Integrity

The proposed rule includes a number of inspection and mechanical integrity requirements that go beyond industry best practices and would not improve safety. Examples include: requiring periodic inspection of BOP equipment to be completed at a single point in time; personnel maintaining BOP equipment to meet OEM training recommendations that do not exist; and specifying testing requirements under extreme and unlikely conditions (which were not, in many cases, part of the design scope). In some cases the proposed requirements reduce safety and could cause harm to the environment. Currently, industry successfully utilizes inspection, certification, and verification processes that balance the availability of existing infrastructure while managing safety and reducing risk. Through the application of robust operational management processes, industry effectively manages risk and delivers beneficial results. Through a staged approach to equipment certification, the processes for inspection and mechanical integrity in use today allow operators to maintain ongoing safe operations and reliable equipment that meets or exceeds the needs of industry.

The process used today, which has proven to be safe and effective, is preferable to the certification approach in the proposed rule, which will require the BOP and (not clearly defined) "every associated system and component" to undergo additional certifications that must be completed by the same inspectors and certifying entities by a common due date. This proposed certification approach will lead to rigs being out of service for extended periods and strain existing certification infrastructure that has been established to support staged inspections. The proposed scheme could result in unintended consequences, such as the degradation of perfectly good, tested, equipment during what would become an expedited project period, while neither reducing risk nor improving safety. Further, expansion of the inspection process dilutes resources and focus, which may also result in increased risk.

BSEE has complete control of the permitting process and the obligation to withdraw an existing permit or deny a new permit if an operator does not have effective systems and processes to manage risk. BSEE's ability to evaluate upcoming and ongoing operations and effectively manage the permitting process (with a primary focus on the operator's ability to employ effective risk management processes) will result in safer and more robust operations. These processes are currently covered by API RP 75 and BSEE's Safety and Environmental Management System (SEMS) rule.

Industry respectfully requests that proposed expansion of the certification process be removed from the rule to avoid negative consequences.

Certification by BSEE-approved verification organizations (BAVOs)

Industry does not see the need for BSEE to approve third party organizations as BAVOs.

If proposed requirements for BAVOs are retained:

- Requirements for certifications by a BAVO should not go into effect until at least 12 months after the initial BAVO list is published.
- If BSEE is to restrict industry's choice of third parties by requiring use of BAVOs, BSEE must establish criteria for verification organizations to ensure they are qualified and adequately staffed with competent personnel to fulfil the role of a verification organization.
- BSEE must also develop and implement a process for providing interpretation of its regulations, and any standards incorporated by reference, to the BAVOs. This process must be made entirely transparent.
- Industry must be provided with a means of recourse to BSEE on decisions made by BAVOs where there is a difference of opinion regarding application or interpretation of a rule or standard.
- BSEE must develop and implement a process to periodically assess and verify that the verification organizations continue to meet BSEE's criteria.
- BSEE should clarify for industry what accountability BSEE is assuming in selecting the verification organizations, and BSEE's expectations on long term management of the verification given that rigs often leave to fulfil contracts overseas and return to areas subject to BSEE jurisdiction.

Overall, the use of BAVOs does not meet the objective to manage and reduce risk to the lowest level practicable. Rather than requiring an additional verification organization, which has a limited understanding of the ultimate service provided, the rule should direct industry to perform risk assessments to determine the optimum equipment inspection requirements and required preventative and mitigating actions for any particular drilling operation.

Economic Analysis

The RIA is flawed and, consistently and substantially underestimates the absolute cost impacts the proposed rule would have. The RIA estimated undiscounted 10-year incremental costs of the rule over baseline totals at approximately \$883 million. An independent cost and economic assessment performed by Blade Energy Partners (Blade) and Quest Offshore (Quest) estimated cumulative 10-year costs at approximately \$32 billion. A copy of the Quest/Blade study is attached (Attachment B) and included for the administrative record.

In addition, the RIA fails to account for and acknowledge the broader economic impacts of the proposed rule on industry and the nation from the immediate and long-term reduction of U.S. offshore oil and natural gas development and production. The proposed rule will likely have significant impacts on offshore oil and natural gas investment, oil and natural gas production, supported employment, U.S. Gross Domestic Product and government revenues. The Quest/Blade analysis projects that the proposed rule relative to baseline would: reduce

cumulative capital investments and other spending by more than 10%; reduce 2030 Gulf of Mexico oil and natural gas production from 3.1 million barrels of oil equivalent to 2.6 million barrels of oil equivalent, a reduction of approximately 15%; reduce total employment supported by Gulf of Mexico offshore development by over 50,000 jobs, as early as 2027; reduce the 10-year cumulative supported U.S. Gross Domestic Product from 2017 to 2026 by \$27 billion; and reduce total collected 10-year government revenues by \$9.9 billion.

The 10-year assessment period is insufficient to fully assess the impact of this proposed rule on OCS operations. Because the rule would apply to development projects and major capital equipment that typically have lifespans of 20-30 years and beyond, it is critical for the BSEE assessment to consider the associated later life impacts.

The associated economic impacts of the proposed drilling margin requirements have not been addressed by BSEE and should be evaluated in order to review the full range of impacts. As described previously, the revised drilling margin requirements will prevent a large number of wells from being drilled or require the addition of casing strings to meet the arbitrary requirements. The Quest/Blade analysis projects that this could reduce the average number of wells drilled per year in the Gulf of Mexico by 26%, significantly impacting total investment in the region. Most of the estimated economic impacts described above are due to new drilling margin requirements. For the subset of wells that could continue with the addition of extra casing strings, the RIA should consider the additional time, risks and actual cost impacts associated with the incremental operations. Similar considerations should be applied for wells impacted by the revised packer fluid requirements that will result in similar well feasibility and redesign issues.

Many of the proposed BOP requirements will require significant time to implement and can only be completed when the rig is out of service, potentially in the field or in a shipyard. The Quest/Blade evaluation of the proposed rule estimates the total 10-year BOP related costs at over \$12 billion. The estimates provided by BSEE in the RIA do not consider these impacts and as a result the impact is drastically underestimated. For example, the increased subsea accumulator requirements may require capital investment for extra bottles that must either be retrofitted to existing BOP frames, complicating and increasing time taken for routine maintenance, or installed subsea as standalone systems that must be deployed on every well and maintained separately. All the impacts noted in Attachment A must be considered in the RIA, to ensure an adequate assessment has been made of all of the proposed changes and that the changes are considered against any potential benefits.

Implementation of the rule has the potential to disrupt normal contracting practices. The numerous provisions of the rule that impose requirements beyond those reflected in API 53 are unlikely to be accepted in the international marketplace, which will likely limit the number of MODUs readily qualified to be contracted for operation in areas under BSEE jurisdiction. As a result, the supply of readily available drilling units would likely be reduced, resulting in increased demand for qualified MODUs and spread rates for lessees, and reduced U.S. drilling and development. These costs and the broader domestic supply and economic impact have not been addressed in the proposed economic analysis.

The timing of contracts may also be affected, as operators would understandably prefer not to contract for the services of a rig that may need to be taken out of service in order to upgrade equipment as provisions of the rule are phased in (e.g., as with the proposed § 250.734(a)(1)), or during periods when significant compliance costs or operational uncertainties may be incurred (e.g., as with the proposed § 250.739(b)).

Retrospective application of manufacturing specifications (e.g., API Spec. 16A, Spec. 16C, and Spec. 16D) to existing equipment effectively prohibits the use of such equipment. Summarily declaring such equipment as unfit has not been justified, and has not been considered in the economic analysis.

The effect of implementing the proposed rule would be particularly acute for self-elevating MODUs (jack-ups) where the equipment is older and the market for their services in the U.S. is already fragile. Very few jack-ups in the U.S. are under term contracts, and the well-to-well nature of these contracts makes it easy for many rigs to be released quickly. Rigzone Data Services reported that in early November 2014, there were 34 marketed jack-ups, 14 more than on June 2, 2015. Of the marketed jack-ups, 21 were then under contract, more than double the number (10) under contract on June 2, 2015. Rigzone also reported the leading edge day rate for a 300-ft, independent-leg cantilever jack-up was \$130,000 in November 2014 versus \$85,000 in June 2015. Further economic assessment by BSEE is required to understand and acknowledge the impact that further degradation of this market will have on businesses which rely on such activity.

Although a broad range of costs has been considered in the RIA, there are a number of potential cost impacts that have been overlooked. An underlying assumption made in the analysis is that the current operating accepted practice is equivalent to the “no action” (OMB Circular A4) baseline (for example SCCE provided by MWCC and HWCG). However, unless the accepted practice is already a minimum regulatory requirement, it should be included as an incremental cost. In addition, potentially significant cost impacts associated with retrofitting existing facilities (i.e. dual bore risers on existing TLPs and SPARs) have not been addressed. If this omission reflects an intended “grandfather” scheme, then regulatory text to provide for the exclusion of existing equipment should be included in the proposed rule.

Finally, consideration should be given to the global energy security implications of a U.S. regulatory activity that could adversely impact U.S. energy production and domestic investment. The U.S. has risen to a position of global energy superpower, and U.S. production has significantly altered the global energy paradigm by adding significant supplies of crude oil to the global marketplace. These added supplies have helped to provide stability to the global marketplace, particularly for our allies who are increasingly looking to the U.S. as a stable oil and natural gas supplier. Here at home, we have the opportunity to embrace the role of energy superpower by encouraging continued investment in critical energy projects, especially in the capital intensive offshore market. BSEE should therefore ensure that any new regulatory requirements are not only safe, feasible, cost-effective, and enforceable, but that they do not unnecessarily erode the strong national security gains that have been achieved through domestic oil and gas production.

Probabilistic Risk Assessments (PRA)

The preamble requests comments related to the practice of utilizing PRA modelling in those operations incorporated within the proposed rule. While PRA may be a useful approach in certain circumstances, it will be of limited value for the oil/natural gas/drilling industry for several reasons. First, there are limited data/inputs (e.g., lack of failure rate data) to develop a meaningful PRA that will provide useful results and a lack of established criteria/benchmarks. There is also a risk of study quality (i.e., lack of standardization) that will lead to variability in results.

The use of PRA methodology will NOT help BSEE in its final decision on this proposed regulation because it will take years to collect the needed data, generate the probabilistic curves, run the analysis, and determine a PRA methodology that generates consistent results via a BSEE model. Nevertheless, BSEE should investigate PRA methodology as well as other Probabilistic Techniques to determine effective techniques that would help BSEE in its future decision making. This review should be done in a collaborative effort with industry, given that industry data will be required.

We strongly suggest that any recommendation on future studies or methods be coordinated with an experienced multidisciplinary team involving process safety engineering experts, drilling and completion experts, well operation experts, and other disciplines relevant for the task. The initial focus should be on developing studies that can focus on the already known challenges and common failure modes (i.e., strength of existing barriers, common failure modes, cultural change, test and verification of equipment considered critical such as gas detectors in the fluids returning from the well, instrumentation for early detection of gas in the riser, etc.).

Applicability to Existing Facilities and Equipment

It is not clear whether existing facilities will be “grandfathered in,” or whether they will have to comply with the new requirements of the rule, a very expensive requirement. Similarly, it is not clear whether equipment already under construction will have to comply with the new requirements if they are finalized or become effective prior to the startup of new facilities; such compliance may not be possible without a significant delay and associated costs. BSEE needs to provide industry with clarity regarding the application of the proposed rule to existing facilities and equipment and consider varied implementation timeframes to meet reasonable expectations. If certain facilities and equipment are not “grandfathered in,” the significant economic impacts must be considered as part of the RIA.

BSEE Solicitation of Information versus Proposed Regulatory Provisions

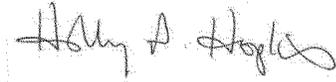
There are over ninety instances in the proposal for which BSEE is soliciting comments but it has not previously engaged industry on the topics or proposed any regulatory text. Our expectation is that BSEE would first engage industry directly in early discussions and then propose regulatory language to give the regulated community the required notice and meaningful opportunity to comment before adopting a final rule on these issues.

Conclusion

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.

Industry appreciates the opportunity to comment on this very important rulemaking and is available for further discussions at your convenience. Please feel free to contact us with any questions.

Sincerely,



Holly Hopkins, API



Alan Spackman, IADC



Daniel Naatz, IPAA



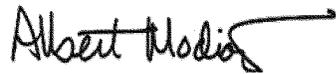
Randall Luthi, NOIA



Evan Zimmerman, OOC



Leslie Beyer, PESA



Alby Modiano, US Oil and Gas Association

Attachments

ATTACHMENT A

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
\$250.107	(3) Utilizing recognized engineering practices that reduce risks to the lowest level practicable when conducting design, fabrication, installation, operation, inspection, repair, and maintenance activities, including: <ul style="list-style-type: none"> (a) Complying with all lease, plan, and permit terms and conditions. (e) The BSEE may issue orders to ensure compliance with this part, including but not limited to, orders to produce and submit records and to inspect, repair, and or replace equipment. The BSEE may also issue orders to shut-in operations of a component or facility because of a threat of serious, irreparable, or immediate harm to health, safety, property, or the environment posed by those operations or because the operations violate law, including a regulation, order, or provision of a lease, plan, or permit. 		Accept proposed text
\$250.107(a)(3)	Utilizing recognized engineering practices that reduce risks to the lowest level practicable when conducting design, fabrication, installation, operation, inspection, repair, and maintenance activities.		Accept proposed text
\$250.107(e)	The BSEE may issue orders to ensure compliance with this part, including but not limited to orders to produce and submit records and to inspect, repair, and or replace equipment. The BSEE may also issue orders to shut-in operations of a component or facility because of a threat of serious, irreparable, or immediate harm to health, safety, property, or the environment posed by those operations or because the operations violate law, including a regulation, order, or provision of a lease, plan, or permit.		Accept proposed text
\$250.198(h)(51)	(51) API RP 2RD, Design of Risers for Floating Production Systems (FPS) and Tension-Leg Platforms (TLPs), First Edition, June 1998; Reaffirmed May 2006, Errata June 2009; incorporated by reference at §§ 250.292, 250.733, 250.800, 250.901, and 250.1002.	Should reference the 2nd edition of 2RD, September 2013	(51) API 2RD, Dynamic Risers for Floating Production Systems, Second Edition, September 2013; incorporated by reference at §§250.292, 250.733, 250.800; 250.901 and 250.1002;
\$250.198(h)(63)	(63) API Standard 53: Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition, November 2012; incorporated by reference at §§ 250.730, 250.737, and 250.739;	Reference API 53 in its entirety. API 53's normative references should be referenced in the rule as the edition that is in effect at the date of manufacture.	Reference API 53 in its entirety with regards to 10A, 16C, and 16D such that only the relevant provisions of those references apply. The editions of API 10A, 16C, and 16D should be those that are in effect at the date of manufacture of the specific equipment.

ATTACHMENT A

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.198(h)(68)	(68) ANSI/API Spec. Q1, Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry, ISO TS 29001:2007 (Identical), Petroleum, petrochemical and natural gas industries—Sector specific requirements—Requirements for product and service supply organizations, Eighth Edition, December 2007, Effective Date: June 15, 2008; incorporated by reference at §§ 250.730 and 250.806	The ninth edition of API Q1 is significantly different from and is no longer a U.S. national adoption of ISO TS 29001:2010. The eighth edition of API Q1 is no longer available from ANSI.	(68) API Spec. Q1, Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry, Ninth Edition, June 2013, incorporated by reference at §§ 250.730 and 250.806
§250.198(h)(70)	(70) ANSI/API Spec. 6A, Specification for Wellhead and Christmas Tree Equipment, Nineteenth Edition, July 2004; Effective Date: February 1, 2005; Contains API Monogram Annex as Part of U.S. National Adoption; ISO 10423:2003 (Modified), Petroleum and natural gas industries—Drilling and production equipment—Wellhead and Christmas tree equipment; Errata 1, September 2004, Errata 2, April 2005, Errata 3, June 2006, Errata 4, August 2007, Errata 5, May 2009; Addendum 1, February 2008; Addendum 2, 3, and 4, December 2008; incorporated by reference at §§ 250.730, 250.806, and 250.1002	The incorporation of API Specification 6A, Specification for Wellhead and Christmas Tree Equipment, should be updated to the Twentieth Edition, October 2010, Effective Date: April 1, 2011, plus Errata 1-4 & Addendum 1-3. ISO 10423 has been reissued, Fourth Edition, 2009-12-15. It should be noted that given that SPPE is required to be "manufactured and marked pursuant to API Spec. Q1" per Section 250.801 (b), then only 6A is applicable as only 6A includes the API monogram program i.e. ISO 10423:2003 is not identical in this regard. API Specification 6A713 First Edition, March 2004 should also be referenced for completeness.	§250.198(h)(70) ANSI/API Spec. 6A, Specification for Wellhead and Christmas Tree Equipment, Specification for Wellhead and Christmas Tree Equipment (includes Errata 1 dated January 2011, Addendum 1 and Errata 2 dated November 2011, Addendum 2 dated November 2012, Addendum 3 dated March 2013, Errata 4 dated August 2013, Errata 5 dated November 2013, Errata 6 dated March 2014, and Errata 7 dated December 2014); incorporated by reference at §§ 250.730, 250.806, and 250.1002.
§250.198(h)(89)	(89) ANSI/API Spec. 11D1, Packers and Bridge Plugs, ISO 14310:2008 (Identical), Petroleum and natural gas industries—Downhole equipment—Packers and bridge plugs, Second Edition, Effective Date: January 1, 2010; incorporated by reference at §§ 250.518, 250.619, and 250.1703	Incorporate the Third Edition by reference. Incorporating the current edition of 11D1 ensures alignment of supplier/manufacturer documentation with the federal rule.	(89) ANSI/API Spec. 11D1, Packers and Bridge Plugs, ISO 14310:2008 (Modified), Petroleum and natural gas industries—Downhole equipment—Packers and bridge plugs, Third Edition; incorporated by reference at §§ 250.518, 250.619, and 250.1703
§250.198(h)(90)	(90) ANSI/API Spec. 16A, Specification for Drill-through Equipment, Third Edition, June 2004; incorporated by reference at § 250.730		In accordance with API Standard 53, as incorporated by reference § 250.198;
§250.198(h)(91)	(91) ANSI/API Spec. 16C, Specification for Choke and Kill Systems, First Edition, January 1993; incorporated by reference at § 250.730		In accordance with API Standard 53, as incorporated by reference § 250.198;
§250.198(h)(92)	(92) API Spec. 16D, Specification for Control Systems for Drilling Well-control Equipment and Control Systems for Diverter Equipment, Second Edition, July 2004; incorporated by reference at § 250.730;		In accordance with API Standard 53, as incorporated by reference § 250.198;
§250.198(h)(93)	(93) ANSI/API Spec. 17D, Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment, Second Edition; May 2011; ISO 13628-4 (Identical), Design and operation of subsea production systems-Part 4: Subsea wellhead and tree equipment; incorporated by reference at § 250.730; and		Accept proposed text

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ATTACHMENT A

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.198(h)(94)	(94) ANSI/API RP 17H, Remotely Operated Vehicle Interfaces on Subsea Production Systems, ISO 13628-8:2002 (Identical), Petroleum and natural gas industries—Design and operation of subsea production systems—Part 8: Remotely Operated Vehicle (ROV) interfaces on subsea production systems, First Edition, July 2004, Reaffirmed: January 2009; incorporated by reference at § 250.734		In accordance with API Standard 53, as incorporated by reference § 250.198;
§250.199(e)(15)	30 CFR subpart, title and/or BSEE Form (OMB Control No.) (15) Subpart O, Well-control and Production Safety Training (1014-0008). BSEE collects this information and uses it to: (i) Evaluate training program curricula for OCS workers, course schedules, and attendance. (ii) Ensure that training programs are technically accurate and sufficient to meet statutory and regulatory requirements, and that workers are properly trained.		Accept proposed text
§250.199(e)(16)	30 CFR subpart, title and/or BSEE Form (OMB Control No.) (16) Subpart P, Sulphur Operations (1014-0006). BSEE collects this information and uses it to: (i) Evaluate sulphur exploration and development operations on the OCS. (ii) Ensure that OCS sulphur operations meet statutory and regulatory requirements and will result in diligent development and production of sulphur leases.		Accept proposed text
§250.199(e)(17)	30 CFR subpart, title and/or BSEE Form (OMB Control No.) (17) Subpart Q, Decommissioning Activities (1014-0010). BSEE collects this information and uses it to: Ensure that decommissioning activities, site clearance, and platform or pipeline removal are properly performed to meet statutory and regulatory requirements and do not conflict with other users of the OCS.		Accept proposed text
§250.199(e)(18)	30 CFR subpart, title and/or BSEE Form (OMB Control No.) (18) Subpart S, Safety and Environmental Management Systems (1014-0017), including Form BSEE-0131, Performance Measures Data. BSEE collects this information and uses it to: (i) Evaluate operators' policies and procedures to assure safety and environmental protection while conducting OCS operations (including those operations conducted by contractor and subcontractor personnel). (ii) Evaluate Performance Measures Data relating to risk and number of accidents, injuries, and oil spills during OCS activities.		Accept proposed text

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.199(e)(19)	<p>30 CFR subpart, title and/or BSEE Form (OMB Control No.) (19) Application for Permit to Drill (APD, Revised APD), Form BSEE-0123, and Supplemental APD Information Sheet, Form BSEE-0123S, and all supporting documentation (1014-0025). BSEE collects this information and uses it to: (i) Evaluate and approve the adequacy of the equipment, materials, and/or procedures that the lessee or operator plans to use during drilling.</p> <p>(ii) Ensure that applicable OCS operations meet statutory and regulatory requirements.</p>		Accept proposed text
§250.199(e)(20)	<p>30 CFR subpart, title and/or BSEE Form (OMB Control No.) (20) Application for Permit to Modify (APM), Form BSEE-0124, and supporting documentation (1014-0026). BSEE collects this information and uses it to: (i) Evaluate and approve the adequacy of the equipment, materials, and/or procedures that the lessee or operator plans to use during drilling and to evaluate well plan modifications and changes in major equipment.</p> <p>(ii) Ensure that applicable OCS operations meet statutory and regulatory requirements.</p>		Accept proposed text

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.292(p)	<p>If you propose to use a pipeline free standing hybrid riser (FSHR) that utilizes a critical chain, wire rope, or synthetic tether to connect the top of the riser to a buoyancy air can, provide the following information in your DWOP in the discussions required by § 250.292(f) and (g):by paragraphs (f) and (g) of this section:</p> <p>(1) A detailed description and drawings of the FSHR, buoy and the tether system;</p> <p>(2) Detailed information on the design, fabrication, and installation of the FSHR, buoy and tether system, including pressure ratings, fatigue life, and yield strengths;</p> <p>(3) A description of how you met the design requirements, load cases, and allowable stresses for each load case according to API RP 2RD (as incorporated by reference in § 250.198);</p> <p>(4) Detailed information regarding the tether system used to connect the FSHR to a buoyancy air can;</p> <p>(5) Descriptions of your monitoring system and monitoring plan to monitor the pipeline FSHR and tether for fatigue, stress, and any other abnormal condition (e.g., corrosion) that may negatively impact the riser or tether; and</p> <p>(6) Documentation that the tether system and connection accessories for the pipeline FSHR have been certified by an approved classification society or equivalent and verified by the CVA</p>	<p>1) FSHR is most attractive solution for a floating production storage unit (FPSO) in the GOM, but it can also be used for other types of floater. .</p> <p>2) The most critical parameter to maintain FSHR integrity is tension. Hence, a tension monitoring system is mandatory. Other parameters requiring monitor may not be realistic or achievable such as fatigue (currently there is no means to directly measure fatigue) and corrosion. Suggest removal of those parameters and instead stressing the use of tension monitoring.</p>	<p>If you propose to use a permanent pipeline free standing hybrid riser (FSHR) that utilizes a critical chain, wire rope, or synthetic tether to connect the top of the riser to a buoyancy air can, provide the following information in your DWOP in the discussions required by § 250.292(f) and (g): by paragraphs (f) and (g) of this section:</p> <p>(1) A detailed description and drawings of the FSHR, buoy and the tether system;</p> <p>(2) Detailed information on the design, fabrication, and installation of the FSHR, buoy and tether system, including pressure ratings, fatigue life, and yield strengths;</p> <p>(3) A description of how you met the design requirements, load cases, and allowable stresses for each load case according to API RP 2RD (as incorporated by reference in § 250.198); or current approved industry standard at the date of manufacture;</p> <p>(4) Detailed information regarding the tether system used to connect the FSHR to a buoyancy air can;</p> <p>(5) Descriptions of your monitoring system and plan for monitoring the riser top tension variation for a permanent FSHR system; and</p> <p>(6) Documentation that the tether system and connection accessories for the pipeline FSHR verified by the CVA and manufactured by a class approved manufacturer.</p>
§250.400	<p>Drilling operations must be conducted in a safe manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the Outer Continental Shelf (OCS), including any mineral deposits (in areas leased and not leased), the National security or defense, or the marine, coastal, or human environment. In addition to the requirements of this subpart, you must also follow the applicable requirements of Subpart G.</p>		<p>Accept proposed text</p>

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.411(a)	Information that you must include with an APD: (a) Plat that shows locations of the proposed well. Where to find a description: § 250.412.		Accept proposed text
§250.411(b)	Information that you must include with an APD: (b) Design criteria used for the proposed well Where to find a description: § 250.413		Accept proposed text
§250.411(c)	Information that you must include with an APD: (c) Drilling prognosis. Where to find a description: § 250.414		Accept proposed text
§250.411(d)	Information that you must include with an APD: (d) Casing and cementing programs. Where to find a description: § 250.415.		Accept proposed text
§250.411(e)	Information that you must include with an APD: (e) Diverter systems descriptions. Where to find a description: § 250.416.		Accept proposed text
§250.411(f)	Information that you must include with an APD: (f) BOP system descriptions. Where to find a description: § 250.731.		Accept proposed text
§250.411(g)	Information that you must include with an APD: (g) Requirements for using an MODU. Where to find a description: § 250.713.		Accept proposed text
§250.412(h)	Information that you must include with an APD: (h) Additional information. Where to find a description: § 250.418.		Accept proposed text
§250.412(h)	Information that you must include with an APD: (h) Additional information. Where to find a description: § 250.418.		Accept proposed text
§250.413(g)	(g) A single plot containing curves for estimated pore pressures, formation fracture gradients, proposed drilling fluid weights, maximum equivalent circulating density, and casing setting depths in true vertical measurements;	This rule requires entry of ECD information into the APD pore pressure/fracture gradient plot. Clarification is needed as to how (depth, mud weight, pump rate) this ECD is expected to be calculated and used. Clear direction is needed to avoid incorrect assumptions, such as comparing actual field data with calculated data since these may be taken at different depths (measured ECD depth may be thousands of feet below the calculated ECD depth at a shoe). A prescriptive requirement that does not address where and how the calculation will be used can result in negative consequences.	(g)A single plot containing estimated pore pressures, formation fracture gradients, proposed drilling fluid weights, equivalent circulating density at the shoe or identified weakest zone (using maximum interval mud weight and flow rate), and casing setting depths in true vertical measurements. This plot will be used for design purposes only. As an alternative, delete ECD reference if unable to specify intended use.
§250.414(c)	(c) Planned safe drilling margins between proposed drilling fluid weights and the estimated pore pressures, and proposed drilling fluid weights and the lesser of estimated fracture gradients or casing shoe pressure integrity test. Your safe drilling margins must meet the following conditions:	Safe drilling margins apply only to "drilling wells" and should not be confused with other operations such as cementing or completions operations. Contrary to the suggestion in the preamble of the proposed rule, the Deepwater Horizon was performing non-drilling well abandonment operations at the time of the incident.	Accept proposed text

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.414(c) (1)	(1) Static downhole mud weight must be greater than estimated pore pressure;	<p>When using Synthetic Based Mud (SBM), there may be a significant difference between Surface Mud Weight (SMW) and Downhole Mud Weight (DHMW) due to compressibility and thermal effects. This delta must be accounted for on deep, complex wells on a case-by-case basis. However, many wells are drilled with Water Based Mud (WBM) or to shallow depths with SBM where the delta is inconsequential. Therefore, the requirement to use DHMW in this clause is overly prescriptive as it will add unnecessary complexity to all wells, thereby diluting the focus of engineering and operational personnel on more pressing process safety issues.</p> <p>An unintended consequence of being overly prescriptive for DHMW is that it may not allow the use of established technologies such as Managed Pressure Drilling. These technologies could require use of DHMW less than the pore pressure, with surface pressure being exerted on the mud column to maintain well control.</p> <p>See attachment C for a comprehensive explanation of the terms used in this comment.</p>	(1) Bottom hole pressure (equivalent mud weight plus surface pressure as applicable) must be greater than estimated pore pressure.
§250.414(c) (2)	(2) Static downhole mud weight must be a minimum of one-half pound per gallon below the lesser of the casing shoe pressure integrity test or the lowest estimated fracture gradient;	<p>Industry acknowledges the safety concerns BSEE has regarding drilling margins and the need for increased vigilance. Avoidance of incidents is paramount, especially in difficult hole sections. Industry has consistently shown the ability to be able to drill without arbitrary prescriptive safety margins, through safe drilling practices.</p> <p>Due the complexity and unintended consequences of a prescriptive drilling margin, please refer to Attachment D for more detail on why a 0.5 ppg drilling margin should not be codified.</p>	<p>It is recommended to delete 250.414 (c) 2.</p> <p>If not deleted, should be changed to: The bottom hole pressure (equivalent mud weight plus surface pressure as applicable) must be below the lesser of the casing shoe integrity test or the lowest actual / estimated fracture gradient, with a risk assessed safety margin consistent with the expected well conditions and current well operations. This is conducted in accordance with API 92L.</p>

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.414(c)(3)	(3) The equivalent circulating density must be below the lesser of the casing shoe pressure integrity test or the lowest estimated fracture gradient;	The industry understands the drilling safety concerns BSEE has with ECD, loss of mud and well control. Industry has successfully managed these processes for many years when drilling in the GOM and other OCS areas. The proposed rule could be interpreted (when combined with all of 250.414) to stop drilling when any lost circulation occurs. A review of 175 OCS wells drilled after June 2010 found that 46% experienced full or partial returns (as defined in API 92L). Utilizing solutions from API 92L, allows a prudent operator to mitigate their risk whereby they may safely drill ahead in a difficult hole section.	(3)The equivalent circulating density must be below the lesser of the casing shoe pressure integrity test or the lowest actual/estimated fracture gradient; if lost circulation occurs, then the losses should be mitigated, and/or ECD managed to reduce the effects of lost circulation as per API 92L.
§250.414(c)(4)	(4) When determining the pore pressure and lowest estimated fracture gradient for a specific interval, you must consider related hole behavior observations.	This section is for planning (prognosis) purposes and should not be applied to operations. Rigorous prognosis preparation is critical to ensure good execution. Refer to API 92L for more information.	(4) When determining the pore pressure and lowest estimated fracture gradient during planning for a specific interval, relevant offset hole behavior observations must be considered.
§250.414(h)	(h) A list and description of all requests for using alternate procedures or departures from the requirements of this subpart in one place in the APD. You must explain how the alternate procedures afford an equal or greater degree of protection, safety, or performance, or why the departures are requested;		Accept proposed text
§250.414(i)	(i) Projected plans for well testing (refer to § 250.460);		Accept proposed text
§250.414(j)	(j) The type of wellhead system and liner hanger system to be installed and a descriptive schematic, which includes but is not limited to pressure ratings, dimensions, valves, load shoulders, and locking mechanisms, if applicable; and		Accept proposed text
§250.414(k)	(k) Any additional information required by the District Manager.		Accept proposed text
§250.415(a)(1)-4)	(a) The following well design information: (1) Hole sizes, (2) Bit depths (including measured and true vertical depth (TVD)), (3) Casing information including sizes, weights, grades, collapse and burst values, types of connection, and setting depths (measured and TVD) for all sections of each casing interval, and (4) Locations of any installed rupture disks (indicate if burst or collapse and rating);		Accept proposed text

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.416	You must include in the diverter descriptions: (a) A description of the diverter system and its operating procedures; (b) A schematic drawing of the diverter system (plan and elevation views) that shows: (1) The size of the annular BOP installed in the diverter housing; (2) Spool outlet internal diameter(s); (3) Diverter-line lengths and diameters; burst strengths and radius of curvature at each turn; and (4) Valve type, size working pressure rating, and location.	All diverters do not use annular elements, some use insert elements which are not the same.	You must include in the diverter descriptions: (a) A description of the diverter system and its operating procedures; (b) A schematic drawing of the diverter system (plan and elevation views) that shows: (1) The size of the sealing element installed in the diverter housing; (2) Spool outlet internal diameter(s); (3) Diverter-line lengths and diameters; burst strengths and radius of curvature at each turn; and (4) Valve type, size working pressure rating, and location
§250.418(g)	A request for approval if you plan to wash out or displace cement to facilitate casing removal upon well abandonment. Your request must include a description of how far below mudline you propose to displace cement and how you will visually monitor returns;		Accept proposed text
§250.420	You must case and cement all wells. Your casing and cementing programs must meet the applicable requirements of this subpart and of Subpart G.	Responses to be found in the individual subparts. This is a high priority response.	
§250.420(a)(6)	(6) Provide adequate centralization to ensure proper cementation; and	The current wording of the requirement needs to be changed to include methods other than centralizers to meet the cementing requirements of the hole section. The language appeared to drive a requirement to place centralizers on all casing strings. There are instances where doing this will actually increase risk. Some of the associated risks include but are not limited to: 1. inability to ream down casing, 2. imposing dog-leg into casing and thereby causing greater casing wear, 3. increase chance of pack-off while circulating and cementing, 4. increase the number of connections in the casing string (because centralizer subs often the only option for centralization), and 5. Damage to wellhead components (due to centralizer pass through).	(6) Provide adequate centralization and/or other methods to aid proper cementation, to meet well design objectives within the constraints imposed by hydraulic, operational, logistical or well architecture limitations (ref. Standard 65-2 2nd Edition Appendix D1)
§250.420(b)(4)	(4) If you need to substitute a different size, grade, or weight of casing than what was approved in your APD, you must contact the District Manager for approval prior to installing the casing.		Accept proposed text

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.421(c)(1)	(1) You must design and conduct your cementing jobs so that cement composition, placement techniques, and waiting times ensure that the cement placed between the bottom joints of casing or liners does not displace more than 500 psi before drilling out the casing or before commencing completion operations.	Industry agrees with the language as written, but would like to ensure that ability to still obtain approval on short liners (<500 ft) is still available on a case by case basis.	
§250.421(c)(2)	(2) You must use a weighted fluid to maintain an overbalanced hydrostatic pressure during the cement setting time, except when cementing casings or liners in riserless hole sections.	This requirement is unclear and needs clarification if the center of the well must be overbalanced or the annular side of the well must be overbalanced. (For further discussion see Attachment E.) 1. Current best practice, when applied correctly, indicates that this is generally not necessary in deepwater. 2. This may be a rule that is appropriate in a small percentage of applications and the rule should be clarified to identify those and make it applicable to only those. 3. It will result in promoting minimal cement fill which will lead to unintended consequences of more potential for casing and more potential for drilling induced bucking which will increase casing wear. Industry understanding is that for deepwater applications 22" & 20" casing is considered surface pipe. If this understanding is not correct, then we take exception.	If this refers to the center of the well, then the following is proposed: "You must use a weighted fluid during displacement to maintain an overbalanced hydrostatic pressure during the cement setting time, except when cementing casings or liners in riserless or diverter hole sections." If this refers to the annular side then the committee takes exception and suggests not adding the text based on the attached documents and computer modeling. (Attachment F and G)
§250.421(b)	Casing type: Conductor; Casing requirements: Design casing and select setting depths based on relevant engineering and geologic factors. These factors include the presence or absence of hydrocarbons, potential hazards, and water depths. Set casing immediately before drilling into formations known to contain oil or gas. If you encounter oil or gas or unexpected formation pressure before the planned casing point, you must set casing immediately and set it above the encountered zone		
§250.421(b)(1)	Casing type: Conductor; Cementing requirements Use enough cement to fill the calculated annular space back to the mudline. Verify annular fill by observing cement returns. If you cannot observe cement returns, use additional cement to ensure fill-back to the mudline. For drilling on an artificial island or when using a well cellar, you must discuss the cement fill level with the District Manager.	Industry understanding is that drivepipe and jetted pipe are considered structural pipe. If this is not correct then we take exception.	

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.421(f)	Casing type: Liners Casing requirements: If you use a liner as surface casing, you must set the top of the liner at least 200 feet above the previous casing/liner shoe. If you use a liner as an intermediate string below a surface string or production casing below an intermediate string, you must set the top of the liner at least 100 feet above the previous casing shoe. You may not use a liner as conductor casing.	The committee was concerned with how casing would be treated in deepwater riserless operations. By providing the two additional requirements of top above mudline and cement back to the mudline, it feels like BSEE's intent can still be met without harming the industry.	Casing type: Liners Casing requirements: If you use a liner as surface casing, you must set the top of the liner at least 200 feet above the previous casing/liner shoe. If you use a liner as an intermediate string below a surface string or production casing below an intermediate string, you must set the top of the liner at least 100 feet above the previous casing shoe. You may not use a liner as conductor casing. A casing string whose top is above the mudline and that has been cemented back to the mudline will be not considered a liner.
§250.423	You must ensure proper installation of casing in the subsea wellhead or liner in the liner hanger.		Accept proposed text
§250.423(a)	(a) You must ensure that the latching mechanisms or lock down mechanisms are engaged upon successfully installing and cementing the casing string.	Leave the language as it is currently codified. The proposed language change does not define success or how to measure it.	(a) You must ensure that the latching mechanisms or lock down mechanisms are engaged upon installation of each casing string.
§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 and cementing the liner.	Leave the language as it is currently codified. The proposed language change does not define success or how to measure it.	(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 installation of the liner.
§250.423(c)	(c) You must perform a pressure test on the casing seal assembly to ensure proper installation of casing or liner. You must perform this test for the intermediate and production casing strings or liners. (1) You must submit for approval with your APD, test procedures and criteria for a successful test. (2) You must document all your test results and make them available to BSEE upon request.		Accept proposed text

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§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.	<p>When combined with 250.414c(2), c(3) and c(4) this rule will become an issue. The 0.5 ppg safe drilling margin added to the restriction of the pore pressure mud weight and ECD requirements will severely limit current and future drilling operations. The joint industry task force identified 110 wells (out of 175 wells reviewed - 63%) that were drilled safely after June 2010 which would not be considered drillable as originally designed if following BSEE proposed rules and practices (Lost circulation or insufficient mud margin).</p> <p>It is important to note that some of these wells might still be drillable if their casing designs were modified, but changing the design of these wells could make them uneconomic to complete as a result of smaller completions, possibly resulting in uneconomical production rates. Depleted zone sidetracks will be affected as most are restricted as to additional casing strings being available. Stopping drilling to set pipe based solely on a legacy (shallow shelf wells) drilling margin will have severe negative consequences for many of the deepwater or depleted zone wells being drilled today and in the future. In addition, containment requirements hinder many deeper well designs such that they no longer have the capability to run additional casing strings.</p> <p>The end result could be a decision to not drill these wells if they are uneconomic to complete and produce. Many of the deeper wells and shallow sidetrack wells have no additional casing options.</p>	(b)The safe drilling margin shall be based on accepted industry practices as documented in API 92L. If a safe drilling margin cannot be maintained then remedial procedures shall be implemented, once risk assessed by the operator and approved by BSEE.
§250.428(b)	If you encounter the following situation: (b) Need to change casing setting depths or hole interval drilling depth (for a BHA with an under-reamer, this means bit depth) more than 100 feet true vertical depth (TVD) from the approved APD due to conditions encountered during drilling operations, <u>Then you must...</u> Submit those changes to the District Manager for approval and include a certification by a professional engineer (PE) that he or she reviewed and approved the proposed changes.		Accept proposed text

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.428(c)	<p>If you encounter the following situation: (c) Have indication of inadequate cement job (such as lost returns, no cement returns to mudline or expected height, cement channeling, or failure of equipment). Then you must... (1) Locate the top of cement by: (i) Running a temperature survey; (ii) Running a cement evaluation log; or (iii) Using a combination of these techniques. (2) Determine if your cement job is inadequate. If your cement job is determined to be inadequate, refer to paragraph (d) of this section. (3) If your cement job is determined to be adequate, report the results to the District Manager in your submitted WAR.</p>	<p>In many applications there are many planned lost return cement jobs that are successful.</p>	<p>If you encounter the following situation: (c) Have indication of inadequate cement job (such as unplanned lost returns, no cement returns to mudline, cement channeling, or failure of equipment). Then you must... (1) Locate the top of cement by: (i) Lift pressure analysis; (ii) Running a temperature survey; (iii) Running a cement evaluation log; or (iv) Use radioactive tracer in cement and logged with LWD when TIR to drill out, (v) drill out and confirm integrity with a shoe test; or (vi) 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.</p>
§250.428(d)	<p>If you encounter the following situation: (d) Inadequate cement job. Then you must... Take remedial actions. The District Manager must review and approve all remedial actions before you may take them, unless immediate actions must be taken to ensure the safety of the crew or to prevent a well-control event. If you complete any immediate action to ensure the safety of the crew or to prevent a well-control event, submit a description of the action to the District Manager when that action is complete. Any changes to the well program will require submittal of a certification by a professional engineer (PE) certifying that he or she reviewed and approved the proposed changes, and must meet any other requirements of the District Manager.</p>	<p>A revised PE certification should only be required if the effectiveness of a barrier has changed. If the effectiveness of a barrier has changed the change should be certified by a PE.</p>	<p>If you encounter the following situation: (d) Inadequate cement job. Then you must... Take remedial actions. The District Manager must review and approve all remedial actions before you may take them, unless immediate actions must be taken to ensure the safety of the crew or to prevent a well-control event. If you complete any immediate action to ensure the safety of the crew or to prevent a well-control event, submit a description of the action to the District Manager when that action is complete. Any changes to the casing or cement program that can impact the effectiveness of the barrier will require submittal of a certification by a professional engineer (PE) certifying that he or she reviewed and approved the proposed changes, and must meet any other requirements of the District Manager.</p>

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.428(k)	If you encounter the following situation: (k) Plan to use a valve on the drive pipe during cementing operations for the conductor casing, surface casing, or liner. Then you must... include a description of the plan in your APD. Your description must include a schematic of the valve and height above the water line. The valve must be remotely operated and full opening with visual observation while taking returns. The person in charge of observing returns must be in communication with the drill floor. You must record in your daily report and in the WAR if cement returns were observed. If cement returns are not observed, you must contact the District Manager and obtain approval of proposed plans to locate the top of cement before continuing with operations.		Accept proposed text
§250.462	What are the source control and containment requirements? For drilling operations using a subsea BOP or surface BOP on a floating facility, you must have the ability to control or contain a blowout event at the sea floor.	Access to Containment Consortium equipment and Mutual Aid Equipment.	What are the source control and containment requirements? For drilling operations using a subsea BOP or surface BOP on a floating facility, you must have the ability to control or contain a blowout event at the sea floor or approved alternate method.
§250.462(a)	(a) To determine your required source control and containment capabilities you must do the following: (1) Consider a scenario of the wellbore fully evacuated to reservoir fluids, with no restrictions in the well. (2) Evaluate the performance of the well as designed to determine if a full shut-in can be achieved without having reservoir fluids broach to the sea floor. If your evaluation indicates that the well can only be partially shut-in, then you must determine your ability to flow and capture the residual fluids to a surface production and storage system.	L1/L2 screening tool is supplied with all permits..	(a) To determine your required source control and containment capabilities you must do the following: (1) Consider a scenario of the wellbore fully evacuated to reservoir fluids, with no restrictions in the well. (2) Evaluate the performance of the well as designed to verify that a full shut-in can be achieved without having reservoir fluids broach to the sea floor. (3) If your evaluation indicates that the well can only be partially shut-in, then you must determine your ability to flow and capture the residual fluids to a surface production and storage system.

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.462(b)	<p>(b) You must have access to and ability to deploy Source Control and Containment Equipment (SCCE) necessary to regain control on the well. SCCE means capping stacks, capping flow systems, riser systems, and vessels whose collective purpose is to control a spill source and stop the flow of fluids into the environment or to contain fluids escaping into the environment. This equipment must include, but is not limited to, the following:</p> <p>(1) Subsea containment and capture equipment, including containment domes and capping stacks; (2) Subsea utility equipment, including hydraulic power, hydrate control, and dispersant injection systems; (3) Remotely operated vehicles (ROVs); (4) Support vessels; and (5) Storage facilities.</p>	<p>It is industry's understanding that a containment dome is the equivalent of a "top hat." Change "top hat" to "dome" and "fluids" to "subsea fluids collection device" and "vessels" to "vessels whose collective purpose is to control a spill source and stop the flow of fluids into the environment or to contain fluids escaping into the environment." This equipment described below before the "This equipment must include..."</p>	<p>(b) You must have access to and ability to deploy Source Control and Containment Equipment (SCCE) necessary to regain control on the well. SCCE means capping stacks, capping flow systems, riser systems, and vessels whose collective purpose is to control a spill source and stop the flow of fluids into the environment. Unless an alternate solution that meets or exceeds the capability of the equipment described below. This must include, but is not limited to, the following:</p> <p>(1) Subsea containment and capture equipment, including containment domes and capping stacks; (2) Subsea utility equipment, including hydraulic power, hydrate control, and dispersant injection systems; (3) Remotely operated vehicles (ROVs); (4) Support vessels; and (5) Storage facilities.</p>
§250.462(c)	<p>(c) You must submit a description of your source control and containment capabilities to the Regional Supervisor and receive approval before BSEE will approve your APD, Form BSEE-0123. The description of your containment capabilities must contain the following: (1) Your source control and containment capabilities for controlling and containing a blowout event at the seafloor, (2) A discussion of the determination required in paragraph (a) of this section, and (3) Information showing that you have access to and ability to deploy all equipment required by paragraph (b) of this section.</p>	<p>This is submitted with each permit (RP checklist). An approved Regional Containment Demonstration would satisfy this requirement.</p>	<p>(c) You must submit a description of your source control and containment capabilities to the Regional Supervisor and receive approval before BSEE will approve your APD, Form BSEE-0123. The description of your containment capabilities must contain the following: (1) Your source control and containment capabilities for controlling and containing a blowout event at the seafloor or approved alternate method, (2) A discussion of the determination required in paragraph (a) of this section, and (3) Information showing that you have access to and ability to deploy all equipment required by paragraph (b) of this section.</p>
§250.462(d)	<p>(d) You must contact the District Manager and Regional Supervisor for resvaluation of your source control and containment capabilities if your: (1) Well design changes, or (2) Approved source control and containment equipment is out of service.</p>	<p>The proposed requirement to advise BSEE for any well design change will necessitate an undue burden on both the operator and BSEE. This is at a time when BSEE is already somewhat undermanned. Thus it is important to designate that only well design changes which negatively impact the results of the WCST require notification to BSEE.</p>	<p>(d) You must contact the District Manager or Regional Supervisor for resvaluation of your source control and containment capabilities if: (1) any changes in the well design or well conditions that require a revised permit to drill to be submitted and can impact the results of the well containment screening tool, or (2) Approved source control and containment equipment is out of service.</p>

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.462(e)(1)	<p>Equipment (1) Capping stacks, Requirements, you must: (i) Function test all pressure holding critical components on a quarterly frequency (not to exceed 104 days between tests). Additional information: Pressure holding critical components are those components that will experience wellbore pressure during a shut-in after being functioned. Requirements, you must: (ii) Pressure test pressure holding critical components on a bi-annual basis, but not later than 210 days from the last pressure test. All pressure testing must be witnessed by BSEE and a BSEE-approved verification organization. Additional information: Pressure holding critical components are those components that will experience wellbore pressure during a shut-in. These components include, but are not limited to: all blind rams, wellhead connectors, and outlet valves. Requirements, you must: (iii) Notify BSEE at least 21 days prior to commencing any pressure testing.</p>	<p>The proposed regulation is not anticipating development of alternative testing methods and frequencies which will provide an equivalent or greater degree of verification. Additionally suggest that BSEE adopt the API terminology of "pressure containing" rather than use "pressure holding" to mitigate the possibility of misinterpretation. Finally, the proposed requirement that both BSEE and a BAVO witness pressure testing is superfluous and does not recognize the scarcity of human resources.</p>	<p>Equipment (1) Capping stacks, Requirements, you must: (i) Function test all pressure containing critical components on a quarterly frequency (not to exceed 104 days between tests) or as otherwise approved by the Regional Supervisor for an alternative testing frequency. Requirements, you must: (ii) Pressure test pressure containing critical components on a bi-annual basis, but not later than 210 days from the last pressure test, or as otherwise approved by the Regional Supervisor for an alternative testing frequency. All pressure testing must be witnessed by BSEE and/or an independent third party. Additional information: Pressure containing critical components are those components that will experience wellbore pressure during a shut-in. These components include, but are not limited to: all blind rams, wellhead connectors, and outlet valves. Requirements, you must: (iii) Notify BSEE at least 21 days prior to commencing any pressure testing.</p>
§250.462(e)(2)	<p>Equipment: (2) Production Safety Systems used for flow and capture operations, Requirements, you must: (i) Meet or exceed the requirements set forth in 30 CFR 250.800-250.808, Subpart H, (ii) Have all equipment unique to containment operations available for inspection at all times.</p>		<p>Equipment: (2) Production Safety Systems used for flow and capture operations, Requirements, you must: (i) Meet the requirements set forth in 30 CFR 250.800-250.808, Subpart H, excluding equipment requirements below the wellhead or that are not applicable to the cap and flow system. (ii) Have all equipment unique to containment operations available for inspection at all times.</p>
§250.462(e)(3)	<p>Equipment: (3) Subsea utility equipment, Requirements, you must: Have all equipment unique to containment operations available for inspection at all times. Additional information Subsea utility equipment includes, but is not limited to: hydraulic power sources, debris removal, hydrate control equipment, and dispersant injection equipment.</p>	<p>The phrase "available for inspection" needs clarification. Debris Removal tooling is provided by the suppliers HPU, Coil Tubing, pumping systems provided by supplier. Companies have contracts with these vendors to provide equipment but do not put specific equipment on retainer.</p>	<p>Equipment: (3) Subsea utility equipment, Requirements, you must: Have all equipment utilized uniquely for containment operations available for inspection at all times.</p>
§250.465(b)(3)	<p>Within 30 days after completing this work, you must submit an End of Operations Report (EOR), Form BSEE-0125, as required under § 250.744.</p>		<p>Accept proposed text</p>

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.500	Well-completion operations must be conducted in a manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the OCS, including any mineral deposits (in areas leased and not leased), the National security or defense, or the marine, coastal, or human environment. In addition to the requirements of this subpart, you must also follow the applicable requirements of Subpart G.		Accept proposed text
§ 250.514	In § 250.514, remove paragraph (d).		
§250.518(e)	(e) Installed packers and bridge plugs must meet the following: (1) All packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198)	Does not apply to temporary packers and bridge plugs, such as used in well servicing applications	(e) After the effective date of this regulation, permanently installed (as defined in the APD and/or APM) packers and bridge plugs must meet the following: (1) All packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198)
§250.518(e)(2)	(2) During well completion operations, the production packer must be set at a depth that will allow for a column of weighted fluids to be placed above the packer that will exert a hydrostatic force greater than or equal to the force created by the reservoir pressure below the packer;	This requirement may compromise well objectives, compromise optimum reservoir recovery, and add risk in some situations. The perceived risk/benefit driving this new requirement is very limited and not necessary or warranted for broad application. It should also be noted that this new requirement and others related to packers may limit, not allow for, or are not applicable for tubingless completions (which can optimize reservoir recovery or add reserves by making uneconomic reserves economic).	The production packer must be set as close as practically possible to the perforated interval. You must ensure that packer setting depth will ensure well integrity for life of well operations including production, intervention and abandonment.
§250.518(e)(3)	(3) The production packer must be set as close as practically possible to the perforated interval; and	The term "as close as practically possible" is unclear, undefined and subject to varying interpretation, making it difficult to comply with. Some completion tools/methods require a certain distance between top perf and packer. In the case of a short or small production liner, it may be highly desirable (improve well reliability and increase reservoir recovery) to place the production packer in the casing just above the production liner.	The production packer must be set as close as practically possible to the perforated interval. You must ensure that packer setting depth will ensure well integrity for life of well operations including production, intervention and abandonment.
§250.518(e)(4)	(4) The production packer must be set at a depth that is within the cemented interval of the selected casing section.	This requirement may compromise well objectives, compromise optimum reservoir recovery, and may add risk, such as when it is preferable to have an uncemented production liner lap and set the production packer within the lap, or when using electric submersible pumps (or other pump) at intermediate to shallow depths in the well.	The production packer must be set as close as practically possible to the perforated interval. You must ensure that packer setting depth will ensure well integrity for life of well operations including production, intervention and abandonment.
§250.518(f)	(f) Your APM must include a description and calculations for how you determined the production packer setting depth.		(f) Your APM must include a description and calculations for how you determined the production packer setting depth and packer fluid selection.

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.600	Well-workover operations must be conducted in a manner to protect against harm or damage to life (including fish and other aquatic life), primary natural resources (the Outer Continental Shelf (OCS) Benthic Habitat, deep-sea hydrocarbon seeps and coastal, or human environment. In addition to the requirements of this subpart, you must also follow the applicable requirements of Subpart G.		
§250.619(e)	(e) If you pull and reinstall packers and bridge plugs, you must meet the following:	Does not apply to temporary packers and bridge plugs, such as used in well servicing applications	(e) After the effective date of this regulation, permanently installed (as defined in the APD and/or APM) packers and bridge plugs must meet the following: Accept proposed text
§250.619(e)(1)	(1) All packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198);		
§250.619(e)(2)	(2) The production packer must be set at a depth that will allow for a column of weighted fluids to be placed above the packer during well completion operations that will exert a hydrostatic force greater than or equal to the force created by the reservoir pressure below the packer.	This requirement may compromise well objectives, compromise optimum reservoir recovery, and add risk in some situations. The perceived risk/benefit driving this new requirement is very limited and not necessary or warranted for broad application. If this proposed rule requires packer fluids to be placed above the packer, the fluids must be completely de-aerated so the wells could not be completed. The density of the packer fluid would not be capable of providing the necessary hydrostatic pressure to compensate for the loss of hydrostatic. The current language doesn't take into consideration future completion plans.	(2) The production packer must be set as close as practically possible to the perforated interval. You must ensure that packer setting depth will ensure well integrity for life of well operations including production, intervention and abandonment
§250.619(e)(3)	(3) The production packer must be set as close as practically possible to the perforated interval, and	The term "as close as practically possible" is unclear, undefined and subject to varying interpretation, making it difficult to comply with. Some completion tools/methods require a certain distance between top production liner. In the case of a short or small production liner, it may be highly desirable (improve well reliability and increase reservoir recovery) to place the production packer in the casing just above the production liner.	(3)The production packer must be set as close as practically possible to the perforated interval. You must ensure that packer setting depth will ensure well integrity for life of well operations including production, intervention and abandonment.

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.619(e)(4)	(4) The production packer must be set at a depth that is within the cemented interval of the selected casing section.	Establishing cement bond via remedial primary cementing can be operationally challenging and extremely costly. The process always requires the perforating of the primary well containment (production casing). Additional steps are required to ensure the primary well containment has not been compromised following the squeeze operations (e.g., squeeze perforations should be tested both positive and negative, which can be difficult to achieve and establishing acceptance / rejection criteria is difficult). Often times an additional production packer is set above the squeeze perforations in order to ensure the exposed perforations do not leak later in life.	(4) The production packer must be set as close as practically possible to the perforated interval. You must ensure that packer setting depth will ensure well integrity for life of well operations including production, intervention and abandonment.
§250.619(f)	(f) Your APM must include a description and calculations for how you determined the production packer setting depth.		(f) Your APM must include a description and calculations for how you determined the production packer setting depth and packer fluid selection.
§250.700	This subpart covers operations and equipment associated with drilling, completion, workover, and decommissioning activities in addition to applicable regulations contained in subparts D, E, F, and Q of this Part unless explicitly stated otherwise.		Accept proposed text
§250.701	You may use alternate procedures or equipment during operations after receiving approval as described in § 250.141 of this Part. You must identify and discuss your proposed alternate procedures or equipment in your Application for Permit to Drill (APD) (Form BSEE-0123) (see § 250.414(h)) or your Application for Permit to Modify (APM) (Form BSEE-0124). Procedures for obtaining approval of alternate procedures or equipment are described in § 250.141 of this part.	Consistency between BSEE Districts on the interpretation and what is acceptable in District and not in the other.	
§250.702	May I obtain departures from these requirements? You may apply for a departure from these requirements as described in § 250.142. Your request must include justification showing why the departure is necessary. You must identify and discuss the departure you are requesting in your APD (see § 250.414(h)) or your APM.	BSEE will require justification for departures. This could result in increasing time burden with no technical benefit. A statement will still ensure operator responsibility.	You may apply for a departure from these requirements as described in § 250.142. Your request must include a statement showing why the departure is necessary. You must identify and discuss the departure you are requesting in your APD (see § 250.414(h)) or your APM.
§250.703	What must I do to keep wells under control? You must take necessary precautions to keep wells under control at all times, including:		Accept proposed text
§250.703(a)	(a) Use recognized engineering practices that reduce risks to the lowest level practicable when monitoring and evaluating well conditions and to minimize the potential for the well to flow or kick;		Accept proposed text
§250.703(b)	(b) Have a person onsite during operations who represents your interests and can fulfill your responsibilities;		Accept proposed text

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
\$250.703(c)	(c) Ensure that the toolpusher, operator's representative, or a member of the rig crew maintains continuous surveillance on the rig floor from the beginning of operations until the well is completed. This includes, but is not limited to, the well with blowout preventers (BOPs), bridge plugs, cement plugs, or packers.		Accept proposed text
\$250.703(d)	(d) Use personnel trained according to the provisions of Subparts O and S.		Accept proposed text
\$250.703(e)	(e) Use and maintain equipment and materials necessary to ensure the safety and protection of personnel, equipment, natural resources, and the environment; and		Accept proposed text
\$250.703(f)	(f) Use equipment that has been designed, tested, and rated for the most extreme service conditions to which it will be exposed while in service.	Unclear requirements	(f) Select equipment that is designed and rated for the anticipated conditions to which it will be exposed while in service.
\$250.710	Prior to engaging in well operations, personnel must be instructed in:		
\$250.710(a)	(a) The safety requirements for the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment as required by Subpart S of this Part. Date and time of safety meetings must be recorded and available at the facility or reviewed by BSEE representatives.		
\$250.710(b)	(b) The well control plan for each well. Each well control plan must contain instructions for personnel about the use of each well-control component of your BOP; procedures that describe how personnel will seal the wellbore and shear pipe before maximum anticipated surface pressure (MASP) conditions are exceeded; assignments for each crew member; and a schedule for completion of each assignment. You must keep a copy of your well-control plan on the rig at all times, and make it available to BSEE upon request. You must post a copy of the well-control plan on the rig floor.		
\$250.711	You must conduct a weekly well-control drill with all personnel engaged in well operations. Your drill must familiarize personnel engaged in well operations with their roles and functions so that they can perform their duties promptly and efficiently as outlined in the well control plan required by § 250.710.		

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.711(a)	(a) Timing of drills. You must conduct each drill during a period of activity that minimizes the risk to operations. The timing of your drills must cover a range of different operations, including drilling with a diverter, on-bottom drilling, and tripping. The same drill may not be repeated consecutively.	Overly prescriptive. Drill should be appropriate for the operations conducted. Revised to be more appropriate for operations being conducted. The restriction on repetition of a drill is inappropriate. Drills are training exercises intended to reinforce procedures, and it may be desirable and appropriate to repeat a drill until a successful outcome is achieved.	(a) Timing of drills. You must conduct each drill during a period of activity that minimizes the risk to operations. The timing of your drills must cover a range of different operations, including drilling with a diverter, on-bottom drilling, and tripping and be appropriate for current operations.
§250.711(b)	(b) <i>Recordkeeping requirements.</i> For each drill, you must record the following in the daily report: (1) Date, time, and type of drill conducted; (2) The amount of time it took to be ready to close the diverter or use each well-control component of BOP system; and (3) The total time to complete the entire drill.		
§250.711(c)	(c) <i>A BSEE ordered drill.</i> A BSEE representative may require you to conduct a well-control drill during a BSEE inspection. The BSEE representative will consult with your onsite representative before requiring the drill.		
§250.712(a)	(a) You must report the movement of all rig units on and off locations to the District Manager using Form BSEE-0144, Rig Movement Notification Report. Rig units include MODUs, platform rigs, snubbing units, wire-line units used for non-routine operations, and coiled tubing units. You must inform the District Manager 72 hours before: (1) The arrival of a rig unit on location; (2) The movement of a rig unit to another slot. For movements that will occur less than 72 hours after initially moving onto location (e.g., coiled tubing and batch operations), you may include your anticipated movement schedule on Form BSEE-0144; or (3) The departure of a rig unit from the location.	Note that this change in the reporting requirement from 24 hour notice to 72 hour notice will likely result in increased inaccurate estimates of operational moves of various unit and rig types due to the potential for operational plans, schedules or sequences to change over these extended time periods. This is likely to result in multiple reporting adjustments being made to BSEE during the anticipated reporting periods. Recommend that this reporting notice be reduced to 48 hours versus the currently proposed 72 hour timeframe. 48 hours is consistent with USCG notification for MODUs.	(a) Prior to commencing operations and at the completion of operations, you must report the movement of all drilling units on and off drilling locations to the District Manager. This includes both MODU and platform rigs. (1) You must inform the District Manager 48 hours before: (i) Prior to commencement of operations, the arrival of an MODU on location; and (ii) at the completion of operations, the departure of an MODU from the location. (2) You must inform the District Manager 24 hours before: (i) The movement of a platform rig to a platform; (ii) The movement of a platform rig to another slot; and (iii) The movement of an MODU to another slot.
§250.712(b)	(b) You must provide the District Manager with the rig name, lease number, well number, and expected time of arrival or departure.		
§250.712(c)	(c) If a MODU or platform rig is to be warm or cold stacked, you must inform the District Manager: (1) Where the MODU or platform rig is coming from; (2) The location of where the MODU or platform rig will be positioned; (3) Whether the MODU or platform rig will be manned or unmanned; and (4) If the location for stacking the MODU or platform rig changes.		

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.712(d)	(d) Prior to resuming operations after stacking, you must notify the appropriate District Manager of any construction, repairs, or modifications associated with the drilling package made to the MODU or platform rig.		
§250.712(e)	(e) If a drilling rig is entering OCS waters, you must inform the District Manager where the drilling rig is coming from.		
§250.712(f)	(f) If you change your anticipated date for initially moving on or off location by more than 24 hours, you must submit an updated Form BSEE-0144, Rig Movement Notification Report.		
§250.713	If you plan to use a MODU or lift boat for well operations, you must provide:		
§250.713(a)	(a) Fitness requirements. Information and data to demonstrate the capability to perform at the proposed location. This information must include the most extreme environmental and operational conditions that the unit is designed to withstand, including the minimum air gap necessary for both hurricane and non-hurricane seasons. If sufficient environmental information and data are not available at the time you submit your APD or APM, the District Manager may approve your APD or APM but require you to collect and report this information during operations. Under this circumstance, the District Manager has the right to revoke the approval of the APD or APM if information collected during operations shows that the MODU or lift boat is not capable of performing at the proposed location.		
§250.713(b)	(b) Foundation requirements. Information to show that site-specific soil and oceanographic conditions are capable of supporting the proposed MODU or lift boat. If you provided sufficient site-specific information in your EP, DPP, or DOCD submitted to BOEM, you may reference that information. The District Manager may require you to conduct additional surveys and soil borings before approving the APD or APM if additional information is needed to make a determination that the conditions are capable of supporting the MODU, lift boat, or equipment installed on a subsea wellhead. For moored rigs, you must submit a plat of the rigs' anchor pattern approved in your EP, DPP, or DOCD in your APD or APM.		

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§250.713(c)	(c) For frontier areas. (1) If the design of the MODU or lift boat you plan to use in a frontier area is unique or has not been proven for use in the proposed environment, the District Manager may require you to submit a third-party review of the MODU or lift boat design. If required, you must obtain a third-party review of your MODU or lift boat similar to the process outlined in §§ 250.915 through 250.918. You may submit this information before submitting an APD or APM. (2) If you plan to conduct operations in a frontier area, you must have a contingency plan that addresses design and operating limitations of the MODU or lift boat. Your plan must identify the actions necessary to maintain safety and prevent damage to the environment. Actions must include the suspension, curtailment, or modification of operations to remedy various operational or environmental situations (e.g., vessel motion, riser offset, anchor tensions, wind speed, wave height, currents, icing or ice-loading, settling, tilt or lateral movement, resupply capability).		
§250.713(d)	(d) <i>Additional documentation.</i> You must provide the current Certificate of Inspection (for US Flagged vessels) or Certificate of Compliance (for Foreign Flagged vessels) from the USCG and Certificate of Classification. You must also provide current documentation of any operational limitations imposed by an appropriate classification society.		
§250.713(e)	(e) Dynamically positioned rig unit. If you use a dynamically positioned MODU, you must include in your APD or APM your contingency plan for moving off location in an emergency situation. Your plan must include, but not be limited to, such emergency events caused by storms, currents, station-keeping failure, power failure, and loss of well-control. The District Manager may require your plan to include additional events and information.		
§250.713(f)	(f) Inspection of unit. The MODU or lift boat must be available for inspection by the District Manager before commencing operations and at any time during operations.		
§250.713(g)	(g) Current Monitoring. For water depths greater than 400 meters (1,312 feet), you must include in your APD or APM: (1) A description of the specific current speeds that will cause you to implement rig shutdown, move-off procedures, or both; and (2) A discussion of the specific measures you will take to curtail rig operations and move off location when such currents are encountered. You may use criteria such as current velocities, riser angles, watch circles, and remaining rig power to describe when these procedures or measures will be implemented.		

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.714	If you use a floating rig unit in an area with subsea infrastructure, you must develop a dropped objects plan and make it available to BSEE upon request. The plan must be updated as the infrastructure on the seafloor changes. Your plan must include:		
§250.714(a)	(a) A description and plot of the path the rig will take while running and pulling the riser;		
§250.714(b)	(b) A plat showing the location of any subsea wells, production equipment, pipelines, and any other identified debris;		
§250.714(c)	(c) Modeling of a dropped object's path with consideration given to metocean conditions for various material forms, such as a tubular (e.g., riser or casing) and box (e.g., BOP or tree);		
§250.714(d)	(d) Communications, procedures, and delegated authorities established with the production host facility to shut-in any active subsea wells, equipment, or pipelines in the event of a dropped object; and	Companies should have SIMOPS procedures in place	
§250.714(e)	(e) Any additional information required by the District Manager.		
§250.715	All jack-up and moored MODUs must have a minimum of two functioning GPS transponders at all times, and you must provide to BSEE real-time access to the GPS data prior to each hurricane season.	New regulation requiring transmission of position data onshore that would be accessed by BSEE	
§250.715(a)	(a) The GPS must be capable of monitoring the position and tracking the path in real-time if the moored MODU or jack-up moves from its location during a severe storm.	New regulation requiring transmission of position data onshore that would be accessed by BSEE	
§250.715(b)	(b) You must install and protect the tracking system's equipment to minimize the risk of the system being disabled.	New regulation requiring transmission of position data onshore that would be accessed by BSEE	
§250.715(c)	(c) You must place the GPS transponders in different locations for redundancy to minimize risk of system failure.	New regulation requiring transmission of position data onshore that would be accessed by BSEE	
§250.715(d)	(d) Each GPS transponder must be capable of transmitting data for at least 7 days after a storm has passed.	New regulation requiring transmission of position data onshore that would be accessed by BSEE	
§250.715(e)	(e) If the MODU is moved off location in the event of a storm, you must immediately begin to record the GPS location data.	New regulation requiring transmission of position data onshore that would be accessed by BSEE	
§250.715(f)	(f) Contact the Regional Office and allow real-time access to the MODU or jack-up location data. When you contact the Regional Office, provide the following: (1) Name of lessee and operator with contact information; (2) Rig/facility/platform name; (3) Initial date and time; and (4) How you provided GPS real-time access.	New regulation requiring transmission of position data onshore that would be accessed by BSEE	

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.720(a)	(a) Whenever you interrupt operations, you must notify the District Manager. Before moving off the well, you must have two independent barriers installed, at least one of which must be a mechanical barrier, as approved by the District Manager. You must install the barriers at appropriate depths within a properly cemented casing string or liner. Before removing a subsea BOP stack or surface BOP stack on a mudline suspension well, you must conduct a negative pressure test in accordance with § 250.721. (1) The events that would cause you to interrupt operations and notify the District Manager include, but are not limited to, the following: (i) Evacuation of the rig crew; (ii) Inability to keep the rig on location; (iii) Repair to major rig or well-control equipment; or (iv) Observed flow outside the well's casing (e.g., shallow water flow or bubbling). (2) The District Manager may approve alternate procedures or barriers in accordance with § 250.141 if you do not have time to install the required barriers or if special circumstances occur.		Accept proposed text
§250.721(a)	(a) You must test each casing string that extends to the wellhead according to the following table:		Accept proposed text
§250.721(a)(1)	Casing type: (1) Drive or Structural, Minimum test Pressure: Not required.		Accept proposed text
§250.721(a)(2)	Casing type: (2) Conductor, excluding subsea wellheads. Minimum test Pressure: 250 psi.		Accept proposed text
§250.721(a)(3)	Casing type: (3) Surface, Intermediate, and Production, Minimum test Pressure: 70 percent of its minimum internal yield.		Accept proposed text
§250.721(b)	(b) You must test each drilling liner and liner-lap to a pressure at least equal to the anticipated leak off pressure of the formation below that liner shoe, or subsequent liner shoes if set. You must conduct this test before you continue operations in the well.	Testing of the liner-lap is not possible. The liner-top can be tested to confirm integrity.	(a) You must test each drilling liner (and liner-top) to a pressure at least equal to the anticipated pressure to which the liner will be subjected during the formation pressure-integrity test below that liner shoe, or subsequent liner shoes if set. The District Manager may approve or require other liner test pressures.
§250.721(c)	(c) You must test each production liner and liner-lap to a minimum of 500 psi above the formation fracture pressure at the casing shoe into which the liner is lapped.	Testing of the liner-lap is not possible. The liner-top can be tested to confirm integrity	(c) You must test each production liner (and liner-top) to a minimum of 500 psi above the formation fracture pressure at the casing shoe into which the liner is lapped
§250.721(d)	(d) The District Manager may approve or require other casing test pressures.		Accept proposed text

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.721(e)	(e) If you plan to produce a well, you must: (1) For a well that is fully cased and cemented, pressure test the entire well to maximum anticipated shut-in tubing pressure before perforating the casing or liner; or (2) For an open-hole completion, pressure test the entire well to maximum anticipated shut-in tubing pressure before you drill the open-hole section.	The proposed language to "pressure test the entire well to maximum anticipated shut-in tubing pressure" is not clearly defined and subject to interpretation. It is not clear if "anticipated shut-in tubing pressure" is with full column of HC or after perforating with an underbalanced fluid. If the context is with full column of HC, it is problematic to implement this when the fluid in the well at time of pressure test is different density than the planned completion fluid. In this situation, the proposed new rule applied literally could require multiple pressure tests with a test packer set at different depth for each test. This could add risk due to multiple pressure tests, inducing multiple stress cycles on the casing and the cement to casing bond, increase the chance of casing failure later in life of the well, and/or increase chance of forming a microannulus. The proposed language would also very likely result in higher test pressure for many wells, particularly high pressure wells, and this would induce greater stress on the casing and casing to cement bond, further increase the chance of casing failure later in life of well, and/or increase the chance of forming a microannulus. Besides the potential unintended negative consequences mentioned above, the historical requirement to test to maximum anticipated SITP, but not to exceed 70% of burst rating, has proven effective and should be continued (the 70% burst rating limit, as practiced, prevents the potential issues mentioned above).	(e) If you plan to produce a well, you must: (1) For a well that is fully cased and cemented, pressure test the entire well to maximum anticipated shut-in tubing pressure, but not to exceed 70% of the burst rating limit of the weakest component, before perforating the casing or liner; or (2) For an open-hole completion, pressure test the entire well to maximum anticipated shut-in tubing pressure, but not to exceed 70% of the burst rating of the weakest component, before you drill the open-hole section.
§250.721(f)	(f) You may not resume operations until you obtain a satisfactory pressure test. If the pressure declines more than 10 percent in a 30-minute test, or if there is another indication of a leak, you must submit to the District Manager for approval your proposed plans to re-cement, repair the casing or liner, or run additional casing/liner to provide a proper seal. Your submittal must include a PE certification of your proposed plans.		Accept proposed text
§250.721(g)	(g) You must perform a negative pressure test on all wells that use a subsea BOP stack or wells with mudline suspension systems.		Accept proposed text
§250.721(g)(1)	(1) You must perform a negative pressure test on your final casing string or liner. This test must be conducted after setting your second barrier just above the shoe track but prior to conducting any completion operations.		(1) If hydrocarbons are present, you must perform a negative pressure test on your final casing string or liner. This test must be conducted after setting your second barrier just above the shoe track but prior to conducting any completion operations.

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.721(g)(2)	(2) You must perform a negative test prior to unlatching the BOP at any point in the well. The negative test must be performed on those components, at a minimum, that will be exposed to the negative differential pressure that will occur when the BOP is disconnected.		Accept proposed text
§250.721(g)(3)	(3) The District Manager may require you to perform additional negative pressure tests on other casing strings or liners (e.g., intermediate casing string or liner) or on wells with a surface BOP stack.		Accept proposed text
§250.721(g)(4)	(4) You must submit for approval with your APD or APM, test procedures and criteria for a successful negative test. If any of your test procedures or criteria for a successful test change, you must submit for approval the changes in a revised APD or APM.		Accept proposed text
§250.721(g)(5)	(5) You must document all your test results and make them available to BSEE upon request.		Accept proposed text
§250.721(g)(6)	(6) If you have any indication of a failed negative pressure test, such as, but not limited to, pressure buildup or observed flow, you must immediately investigate the cause. If your investigation confirms that a failure occurred during the negative pressure test, you must: (i) Correct the problem and immediately notify the appropriate BSEE District Manager and (ii) Submit a description of the corrective action taken and receive approval from the appropriate BSEE District Manager for the retest.		Accept proposed text
§250.721(g)(7)	(7) You must have two barriers in place, as described in § 250.420(b)(3), at any time and for any well, prior to performing the negative pressure test.		(7) if hydrocarbons are present, you must have two barriers in place, as described in § 250.420(b)(3), prior to performing the negative pressure test.
§250.721(g)(8)	(8) You must include documentation of the successful negative pressure test in the End-of-Operations Report (Form BSEE-0125).		Accept proposed text
§250.722	If wellbore operations continue within a casing or liner for more than 30 days from the previous pressure test or BSEE approved verification of the well's casing or liner, you must:		If wellbore operations continue within a casing or liner for more than 30 days from the previous pressure test or independent third party review of the well's casing or liner, you must:

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.722(a)	<p>(a) Stop operations as soon as practicable, and evaluate the effects of the prolonged operations on continued operations and the well. As a minimum, you must: (1) Evaluate the well casing with either a pressure test or caliper tool. On a case-by-case basis the District Manager may require a specific method of evaluation; and (2) Report the results of your evaluation to the District Manager and obtain approval of those results before resuming operations. Your report must include calculations that show the well's integrity is above the minimum safety factors.</p>		<p>(a) Stop operations as soon as practicable, and evaluate the effects of the prolonged operations on continued operations and the well. As a minimum, you must: (1) Evaluate the well casing with either a pressure test, caliper tool, or imaging tool. On a case-by-case basis the District Manager may require a specific method of evaluation; and (2) Report the results of your evaluation to the District Manager and obtain approval of those results before resuming operations. If an imaging tool or caliper is used, then your report must include calculations that show the well's integrity is above the minimum safety factors.</p>
§250.722(b)	<p>(b) If well integrity has deteriorated to a level below minimum safety factors, you must: (1) Obtain approval from the District Manager to begin repairs or install additional casing. To obtain approval, you must also provide a PE certification showing that the site is reviewed and approved by a professional engineer; (2) Repair the casing to meet the minimum safety factors; and (3) Perform a pressure test after the repairs are made or additional casing is installed and report the results to the District Manager as specified in § 250.721.</p>		<p>Accept proposed text</p>
§250.723	<p>You must take the following safety measures when you conduct operations with a rig unit or lift boat on or jacked-up over a platform with producing wells or that has other hydrocarbon flow:</p>		
§250.723(a)	<p>(a) The movement of rig units and related equipment on and off a platform or from well to well on the same platform, including rigging up and rigging down, must be conducted in a safe manner;</p>		
§250.723(b)	<p>(b) You must install an emergency shutdown station for the production system near the rig operator's console;</p>		
§250.723(c)	<p>(c) You must shut-in all producible wells located in the affected wellbay below the surface and at the wellhead when: (1) You move a rig unit or related equipment on and off a platform; this includes rigging up and rigging down activities within 500 feet of an affected platform; (2) In-situ completion operations are performed on a platform; and (3) A MODU or lift boat moves within 500 feet of a platform. You may resume production once the MODU or lift boat is in place, secured, and ready to begin operations.</p>		

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.723(d)	(d) All wells in the same well-bay which are capable of producing hydrocarbons must be shut-in below the surface with a pump-through-type tubing plug and at the surface with a closed master valve prior to moving rig units and related equipment unless otherwise approved by the District Manager. (1) A closed surface-controlled subsurface safety valve of the pump-through-type may be used in lieu of the pump-through-type tubing plug provided that the surface control has been locked out of operation. (2) The well to which a rig unit or related equipment is to be moved must be equipped with a back-pressure valve prior to removing the tree and installing and testing the BOP system. (3) The well from which a rig unit or related equipment is to be moved must be equipped with a back pressure valve prior to removing the BOP system and installing the production tree.		
§250.723(e)	(e) Coiled tubing units, snubbing units, or wireline units may be moved onto and off of a platform without shutting in wells.		
§250.724	(see Preamble)	<p>This requires operators to monitor Deepwater and HPHT operations in Real Time.</p> <p>Smaller Operators may not be able to implement in this time frame along with having cost issues. BSEE has not sufficiently justified the use of real-time monitoring and its potential effect on safety.</p> <p>Unknown what degree of real-time monitoring is required to ensure functionality and operability is sufficient to meet BSEE expectations.</p> <p>Current capability may need to be upgraded. More economic analysis is required to obtain valid numbers.</p> <p>Real time system can't easily be turned on and off, it requires increased communication capability, and people to operate it expect to work year round.</p> <p>Real cost is significantly higher which affects smaller operator.</p> <p>Once installed, a remote RTC is a fixed operating cost that can be allocated as per the number of operations. The cost is still there regardless if there are operations. A minimum daily operating cost for a remote RTC is \$40,000. This is exclusive of the set up charge for the facility and monthly cost for the facility.</p>	

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.724(c)	(a) When conducting well operations with a subssea BOP or surface BOP on a floating facility, or when operating in an IHPIT environment, you must, within 3 years of publication of the final rule, submit to the BSEE a report detailing the design, development, independent, automatic and continuous monitoring system capable of recording, storing, and transmitting all aspects of: (1) the BOP control system; (2) The well's fluid handling systems on the rig; and (3) The well's downhole conditions with the bottom hole assembly tools (if any tools are installed).	Rulemaking on RTM is premature. BSEE has contracted the Transportation Research Board of the National Academies to advise the agency on the use of real-time monitoring systems by industry and government. The final report of the Transportation Research Board should be fully considered by BSEE and the public before any rulemaking on RTM is finalized. Data collection points to be added to subssea discrete and surface BOP systems. Adds pressure temperature probes to the stack. Bandwidth and reliability is not reliable due to weather, crane movements, and the service provider. Significant cost to develop and integrate into existing systems. Possible entry point into a safety system for attack or mis. Cyber security would be required. Monitor all real-time operators center Monitor all real-time operators center	Remove §250.724(a), (b), (c) If not removed, change to: (a) During well operations, with a subssea BOP or surface BOP on a floating facility, or when operating in an IHPIT environment, you must gather and monitor real-time well data using a system capable of recording, storing, and transmitting data as identified in a Real Time Monitoring Plan. Within 3 years of publication of the final rule, the Real Time Monitoring Plan must address [1] the fluid circulating system and [2] bottom hole tools. Within 5 years of publication of the final rule, the Real Time Monitoring Plan must address the BOP status.
§250.724(b)	(b) You must immediately transmit these data as they are gathered to a designated onshore location during operations where they must be monitored by qualified personnel who must be in continuous contact with rig personnel during operations. After operations, you must preserve and store this data at a designated location for recordkeeping purposes as required in §§ 250.740 and 250.741. You must designate the location where the data will be stored and monitored during operations in your APD or APM. The location and the data must be made accessible to BSEE upon request.	Rulemaking on RTM is premature. BSEE has contracted the Transportation Research Board of the National Academies to advise the agency on the use of real-time monitoring systems by industry and government. The final report of the Transportation Research Board should be fully considered by BSEE and the public before any rulemaking on RTM is finalized.	Remove §250.724(a), (b), (c) If not removed, change to (b) During well operations, real-time data must be transmitted to a designated onshore location and the data must be monitored by qualified personnel, as defined in the Real Time Monitoring Plan. Where defined in the Real Time Monitoring Plan, the onshore monitoring personnel must have the capabilities to communicate with rig personnel during operations. After operations, the data must be preserved and stored at a designated location for recordkeeping purposes as required in §§ 250.740 and 250.741. The location and the data must be made accessible to BSEE
§250.724(c)	(c) If you lose any real-time monitoring capability during operations covered by this section, you must immediately notify the District Manager. The District Manager may require other measures until real-time monitoring capability is restored.	Rulemaking on RTM is premature. BSEE has contracted the Transportation Research Board of the National Academies to advise the agency on the use of real-time monitoring systems by industry and government. The final report of the Transportation Research Board should be fully considered by BSEE and the public before any rulemaking on RTM is finalized.	Remove §250.724(a), (b), (c) If not removed, change to (c) The Real Time Monitoring Plan must define a protocol if real-time monitoring capabilities are lost during operations covered by this section.

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.730(a)	<p>(a) You must design, install, maintain, inspect, test, and use the BOP system and system components to ensure well control. The working-pressure rating of each BOP component must exceed MASP as defined for the operation. For a subsea BOP, the MASP must be taken at the mudline. The BOP system includes the BOP stack, control system, and any other associated system(s) and equipment. The BOP system and individual components must be able to perform their expected functions and be compatible with each other. Each ram (excluding casing shear/supershear) must be capable of closing and sealing the wellbore at all times, including under flowing conditions as defined for the operation and specific well conditions, without losing ram closure time and sealing integrity due to the corrosiveness, volume, and abrasiveness of any fluids in the wellbore that you may encounter. Your BOP system must meet the following requirements:</p>	<p>Exclude components above the uppermost ram preventer (e.g., annular and LMPP or riser connect.) Replace "design" with "select." Annular BOPs capable of meeting the specified pressure rating are not available and are not considered technologically feasible in the near term. Limit this regulation to lower stack components including and below the uppermost ram.</p> <p>Empirically, industry has demonstrated the capability to successfully seal the wellbore under a variety of flowing conditions, e.g., flow checks using an annular BOP. However, the proposed regulation, as drafted, calls for each ram to be assessed against an absolute worst case design level event.</p> <p>The goal should be for the BOP system to reliably shut-in the well under reasonably anticipated flowing conditions. Criteria for such anticipated flowing conditions are not presently defined.</p> <p>Industry proposes establishing a working group to work with BSEE to establish industry guidelines for future qualification of BOP system performance under flowing conditions, based on data available from BSEE and industry sources.</p> <p>Industry proposes establishing a working group to work with BSEE to establish industry guidelines for future qualification of BOP performance under flowing conditions, based on data available from BSEE and industry sources</p>	<p>250.730 (a) You must select, install, maintain, inspect, test, and use the BOP system and system components to ensure well-control. The working-pressure rating of each BOP component (ram BOP, gate valve, choke and kill, and wellhead connector) must exceed MAWHP as defined for the operation.</p> <p>For a subsea BOP, the MAWHP must be taken at the mudline.</p> <p>The BOP system includes the BOP stack, control system, and any other associated system(s) and equipment.</p> <p>The BOP system and individual components must be able to perform their expected functions and be compatible with each other.</p> <p>Each ram (excluding casing shear/supershear) must be capable of closing and sealing the wellbore for each well under the anticipated flowing conditions for annular and ram sealability as defined in the APD, and will be based on early detection, for the operation and specific well conditions, without losing ram closure time and sealing integrity due to the corrosiveness, volume, and abrasiveness of any fluids in the wellbore that you may encounter.</p> <p>Your BOP system must meet the following requirements:</p>
§250.730(a)(1)	<p>(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.</p>	<p>API 53 was agreed by industry but the WCR obfuscates the interpretation of the standard</p> <p>Corresponding incorporation by reference of dated equipment manufacturing standards is problematic as it renders equipment manufactured prior to the standard, or to earlier version of the standards obsolete. No justification has been given for such action. The equipment is manufactured to the edition in publication at the time of manufacture. Reference API 53 only and that document will lead to the revised language in the next edition to close this gap.</p>	<p>API 53 in its entirety applies. With regards to dated references, only the relevant provisions of those references apply. The applicable editions of dated references should be those in effect at the date of manufacture of the specific equipment.</p>

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.730(a)(2)	(2) The following industry standards (all incorporated by reference in § 250.198): (i) ANSI/API Spec. 6A; (ii) ANSI/API Spec. 16A; (iii) ANSI/API Spec. 16C; (iv) API Spec. 16D; and (v) ANSI/API Spec. 17D.	BSEE needs to provide guidelines on the intended use for referencing these standards	Reference API 53 in its entirety with regards to 6A, 16A, 16C, 16D, and 17D, such that only the relevant provisions of those references apply. The editions of API 6A, 16A, 16C, 16D, and 17D should be those that were in effect at the date of manufacture of the specific equipment.
§250.730(a)(3)	§250.730(a)(3) For surface and subsea BOPs, the pipe and variable bore rams installed in the BOP stack must be capable of effectively closing and sealing on the tubular body of any drill pipe, workstring, and tubing in the hole under MASP, as defined for the operation, with the proposed regulator settings of the BOP control system.	With control lines etc. – this isn't achievable. This is a show-stopper for running tubing. Need clarification regarding "proposed regulator settings" as this potentially conflicts with API 53. Understanding regulator setting requirements will help industry proposed text that will be better	(3) For surface and subsea BOPs, the pipe and variable bore rams installed in the BOP stack must be capable of effectively closing and sealing on the tubular body of any drill pipe, workstring, and tubing in the hole as defined by the operation. For tubing with control lines, flat packs, or other auxiliary equipment strapped to the tube and across the BOP, a risk assessment shall be used to mitigate well flow risks and to implement control measures for BOP shut-in if required. Regulator settings for ram preventers will be adjusted above normal operating pressure if shut in conditions warrant
§250.730(a)(4)	§250.730(a)(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.		Accept proposed text
§250.730(b)	250.730(b) You must design, fabricate, maintain, and repair your BOP system according to the requirements contained in this subpart, OEM recommendations unless otherwise directed by BSEE, and recognized engineering practices. The training and qualification of repair and maintenance personnel must meet or exceed any OEM training recommendations unless otherwise directed by BSEE.	Recommend replace "design and fabricated" with "select." Second sentence isn't viable as OEMs do not presently publish T&Q recommendations. Equipment owner is already establishing standards IAW SEMS and Subpart O requirements. Definition of OEM should be clarified to indicate the component manufacturer or the system supplier	(b) You must select, maintain, and repair your BOP system according to the requirements contained in this subpart, API 53, and OEM recommendations unless otherwise directed by BSEE. The training and qualification of repair and maintenance personnel must be established in accordance with §250.1915 of this part and meet the requirements of §250.1503 of this part, unless otherwise directed by BSEE.
§250.730(c)	(c) You must follow the failure reporting procedures contained in API Standard 53, ANSI/API Spec. 6A, and ANSI/API Spec 16A, and:	BSEE needs to provide guidelines on the intended use for referencing these standards Spec 6A and 16A references should not be identified as the qualifying reference as they are manufacturing related failure reporting methods. API 53 is an operational document.	(c) You must follow the failure reporting procedures contained in API Standard 53 and:

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.730(c)(1)	(1) You must provide a written report of equipment failure to the manufacturer of such equipment within 30 days after the discovery and identification of the failure.	The beta test group (7 drilling contractors) is already reporting all failures, which we define as the inability of the equipment to function as defined, to a common database. The database automatically copies the reports to the respective OEM fulfilling the requirements of API 53 and 250.730(c)	(1) You must ensure a written report of equipment failure is provided to the manufacturer of such equipment within 30 days after the discovery and identification of the failure. A failure is defined as the inability of the equipment to function as required.
§250.730(c)(2)	(2) You must ensure that an investigation and a failure analysis are initiated within 60 days of the failure to determine the cause of the failure. If the investigation and analysis are performed by an entity other than the manufacturer, you must ensure that the manufacturer receives a copy of the analysis.	Not every failure warrants a full investigation. Repeat failures warrant changes to the equipment, not repeat investigations.	(2) Within 60 days of a failure, you must ensure that an investigation is initiated to determine the cause of the failure. If the investigation is performed by an entity other than the manufacturer, you must ensure that the manufacturer receives the results of the investigation.
§250.730(c)(3)	(3) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed, or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such notice or change, report the design change or modified procedures in writing to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; HE 3314; 45600 Woodland Road, Sterling, Virginia 20166.	This should be addressed under SEMS requirements (MOC); new version of API SPEC 16A is aligned with API 53. Question why this report is being sent to HQ office instead of the District Supervisor as the standard path listed in this rulemaking. Clarify which entity is required to notify BSEE (e.g., contractor or operator involved in the original failure).	(3) If the equipment manufacturer, or equipment owner, notifies you that the design, operating or repair procedures has changed as a result of the failure reference in § 250.730(c)(1), then you must, within 30 days of such notice or change, report the design change or modified procedures in writing to the District Supervisor; Bureau of Safety and Environmental Enforcement; HE 3314; 45600 Woodland Road, Sterling, Virginia 20166
§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 API Spec. Q1 (as incorporated by reference in § 250.198) quality management system. Such quality management system must be certified by an entity that meets the requirements of ISO 17011.	There is no API standard for a BOP stack. Spec. Q1 would apply only to the individual components. ISO 17011 is an incorrect reference. ISO 17021 is the correct reference that should be applied to organizations which certify that quality management systems meet the requirement of a particular reference.	(d) If you plan to use BOP equipment and components manufactured after the effective date of this regulation, you must use equipment and components manufactured under a quality management system certified to API Spec Q1 (as incorporated by reference in § 250.198). The entity certifying such quality management system must meet the requirements of ISO 17021.
§250.730(d)(1)	(1) The BSEE may consider accepting equipment manufactured under quality assurance programs other than API Spec. Q1, provided you submit a request to BSEE containing relevant information about the alternative program and receive BSEE approval under § 250.141.	ISO 9001:2015 and ISO TS29001 are perceived as inadequate in its fit-for-purpose application in this instance (ISO TS29001/API 8th edition contains 37 supplemental requirements beyond ISO 9001:2008 and API 9th edition contains 93 additional requirements beyond API 8th edition). If alternate QMS systems are used, user/purchasers have to invest time/resources to insure QMS meets the requirements of API Q1.	Accept proposed text
§250.730(d)(2)	(2) You must submit this request to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; HE 3314; 45600 Woodland Road, Sterling, Virginia 20166.	See comments on §250.730(d)(1).	Delete this clause.

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.731	<p>For any operation that requires the use of a BOP, you must include the information listed in this section with your applicable APD, APM, or other submittal. You are required to submit this information only once for each well, unless the information changes from what you provided in an earlier approved submission or you have moved off location from the well. After you have submitted this information for a particular well, subsequent APMs or other submittals for the well should reference the approved submittal containing the information required by this section and confirm that the information remains accurate and that you have not moved off location from that well. If the information changes or you have moved off location from the well, you must submit updated information in your next submission.</p>		
§250.731(a)(1)-9)	<p>You must submit: (a) A complete description of the BOP system and system components, including: (1) Pressure ratings of BOP equipment;</p> <p>(2) Proposed BOP test pressures (for subsea BOPs, include both surface and corresponding subsea pressures);</p> <p>(3) Rated capacities for liquid and gas for the fluid-gas separator system;</p> <p>(4) Control fluid volumes needed to close, seal, and open each component;</p> <p>(5) Control system pressure and regulator settings needed to achieve an effective seal of each ram BOP under MASP as defined for the operation;</p> <p>(6) Number and volume of accumulator bottles and bottle banks (for subsea BOP, include both surface and subsea bottles);</p> <p>(7) Accumulator pre-charge calculations (for subsea BOP, include both surface and subsea calculations);</p> <p>(8) All locking devices; and</p> <p>(9) Control fluid volume calculations for the accumulator system (for a subsea BOP system, include both the surface and subsea volumes).</p>	Administrative burden.	

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.73110(1)-10)	<p>You must submit: (b) Schematic drawings, including: (1) The inside diameter of the BOP stack, (2) Number and type of spoolovers (including blade type for shear ram(s)), (3) All locking devices, (4) Size range for variable bore ram(s), (5) Size of fixed ram(s), (6) All control systems with all alarms and set points labeled including pods, (7) Location and size of choke and kill lines (and gas bleed line(s) for subsea BOP), (8) Associated values of the BOP system, (9) Control station locations, and (10) A cross-section of the riser for a subsea BOP system showing number, size, and labeling of all control, supply, choke, and kill lines down to the BOP.</p>		<p>You must submit: (b) Schematic drawings, including: (1) The inside diameter of the BOP stack, (2) Number and type of spoolovers (including blade type for shear ram(s)), (3) All locking devices, (4) Size range for variable bore ram(s), (5) Size of fixed ram(s), (6) All control systems with all alarms and set points labeled including pods, (7) Location and size of choke and kill lines (and gas bleed line(s) for subsea BOP), (8) Associated values of the BOP system, (9) Control station locations, and (10) A cross-section of the riser for a subsea BOP system showing number, size, and labeling of all control, supply, choke, and kill lines down to the BOP.</p>

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.731(c)	<p>You must submit: (c) Certification by a BSEE-approved verification organization, including: Verification that: (1) Test data clearly demonstrates the shear ram(s) will shear the drill pipe at the water depth as required in § 250.732; (2) The BOP was designed, tested, and maintained to perform at the most extreme anticipated conditions; and (3) The accumulator system has sufficient fluid to function the BOP system without assistance from the charging system.</p>	<p>(1) Shear testing at water depth may imply the BOP is in an environment that simulates the required water depth instead of on surface as we currently do. Delete water depth text. (2) The most extreme conditions could mean shear testing with RWP in the wellbore or under flowing conditions. This is not practical or safe to do in a lab. Delete extreme conditions text. (3) Current protocol API 53 addresses the operational side however; this language indicates an impact on S16A and 16D The "most extreme" anticipated conditions needs definition Flow isn't part of the manufacturer's design parameters. Refer back to 250.198 for design parameters. BAVOs don't currently exist and could result in a potential bottleneck. "Test data" implies that a shearing test must be provided for each configuration. Clarification of BSEE's intent is required. API does not address Extreme Conditions. API 53 does identify operations and maintenance. Not to be considered for Spec upgrades because we are unable to identify "extreme anticipated conditions". Industry has addressed the issues for volume requirements. There is a conflict between what BSEE has required and what API 53 and the current work in the specifications are working toward. Coiled tubing and other referenced operations will be greatly impacted if they have to incorporate the BOP specifications. Putting the same requirements on CT operations (response times) will negatively impact CT operational safety.</p>	<p>You must submit: (c) Certification by a qualified independent third party, including: Verification that: (1) Test data and supporting engineering calculations clearly demonstrates the shear ram(s) will shear the drill pipe at the water depth as required in § 250.732; (2) The BOP was designed, tested, and maintained to perform at the most extreme anticipated conditions as defined in the APD and/or APM; and (3) The accumulator system is in accordance with API 53.</p>

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§250.731(d)	250.731(d) You must submit: (d) Additional certification by a BSEE-approved verification organization, if you use a subsea BOP, a BOP in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility. Including: Verification that: (1) The BOP stack is designed for the specific equipment on the rig and for the specific well design; (2) The BOP stack has not been compromised or damaged from previous service; and (3) The BOP stack will operate in the conditions in which it will be used.	BOP stacks aren't designed for specific equipment on a rig; Rather, they are selected in consideration of such equipment. Change to "is suitable for use with" BAVOs don't currently exist. Can a BAVO certify that a stack has not been compromised from previous service?	You must submit: (d) Additional certification by a third party organization, if you use a subsea BOP, a BOP in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility. Including: Verification that: (1) The BOP stack is suitable for use with the specific equipment on the rig and for the specific well design; (2) The BOP stack's ability to function as required has not been compromised from previous service; and (3) The BOP stack will operate in the conditions in which it will be used.
§250.731(e)	You must submit: (e) If you are using a subsea BOP, descriptions of autoshear, deadman, and emergency disconnect sequence (EDS) systems, including: A listing of the functions with their sequences and timing.	Additional Burden. Add "if installed" after EDS systems.	You must submit: (e) If you are using a subsea BOP, descriptions of autoshear, deadman, and emergency disconnect sequence (EDS) systems if installed, including: A listing of the functions with their sequences and timing.
§250.731(f)	You must submit: (f) Certification stating that the Mechanical Integrity Assessment Report required in § 250.732(d) has been submitted within the past 12 months for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility.	Assume this is only required if an APD/APM has not been submitted in the previous 12 months. If it is addition too then it appears to be an unnecessary time and expense burden.	You must submit: (f) Certification stating that the BOP and Well Compatibility Certificate, as required in an APD/APM has been submitted to the Chief, Office of Regulatory Programs: Bureau of Safety and Environmental Enforcement: 45600 Woodland Road, Sterling, Virginia, 20166, within the past 12 months.
§250.732	What are the BSEE-approved verification organization requirements for BOP systems and system components?	Adversely affects rigs that work overseas. Issue exist to operate in the GOM if equipment is not "monitored during its entire lifecycle". Recertification may not be economical and technically impractical to achieve.	What are the independent third-party requirements for BOP systems and system components?
§250.732(a)	(a) The BSEE will maintain a list of BSEE-approved verification organizations that you may use. For an organization to become a BSEE approved verification organization, it must submit the following information to the Chief, Office of Regulatory Programs: Bureau of Safety and Environmental Enforcement: 45600 Woodland Road, Sterling, Virginia, 20166, for BSEE review and approval:	If retained in the rule, §250.732(a) should not go into effect until 12 months after the initial BSEE-approved Verification Organization list is published.	(a) In independent third party providing certification or verification services under subparts D and G of this part must have:
§250.732(a)(1)	(1) Previous experience in verification or in the design, fabrication, installation, repair, or major modification of BOPs and related systems and equipment;	The requisite experience is in the verification of the design.	(1) Previous experience in verification of the design, fabrication, installation, repair, or major modification of BOPs and related systems and equipment
§250.732(a)(2)	(2) Technical capabilities;		Remove
§250.732(a)(3)	(3) Size and type of organization;		Remove
§250.732(a)(4)	(4) In-house availability of, or access to, appropriate technology. This should include computer programs, hardware, and testing materials and equipment;		Renumber

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§250.732(a)(5)	(5) Ability to perform the verification functions for projects considering current commitments;		Renumber
§250.732(a)(6)	(6) Previous experience with BSEE requirements and procedures; and		Renumber
§250.732(a)(7)	(7) Any additional information that may be relevant to BSEE's review.		Remove
§250.732(b)	(b) Prior to beginning any operation requiring the use of any BOP, you must submit verification by a BSEE-approved verification organization and supporting documentation as required by this paragraph to the appropriate District Manager and Regional Supervisor.	"	(b) 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.
§250.732(b)(1)i	You must submit verification and documentation related to: (1) Shear testing, That: (i) Demonstrates that the BOP will shear the drill pipe and any electric-, wire-, slick-line to be used in the well;	As written, this would shut down many drilling operations for a long period as many rigs do not currently have shearing capability that would conform in regard to the electric-, wire-, slick-line requirement. Replace BOP with shear ram to confirm it doesn't need to be specific to a particular BOP assembly. Extend the requirement for Non-drill pipe to 5 years (e.g., wire-line)	You must submit verification and documentation from an independent third party related to: Shear testing, That: (i)(a) Demonstrates that the required sealing shear ram will shear the drill pipe to be used in the well; (i)(b) Demonstrates that the required sealing shear ram will also shear any electric, wire, slick-line in the well within 5 years.
§250.732(b)(1)ii	(ii) Demonstrates the use of test protocols and analysis that represent recognized engineering practices to ensure repeatability, reproducibility of the test, and that the testing was performed by a facility that meets generally accepted quality assurance standards;	This wording is vague and unclear. It would be very difficult to know when/if conformance was achieved.	
§250.732(b)(1)iii	(iii) Provides a reasonable representation of field applications, taking into consideration the physical and mechanical properties of the drill pipe;	The actual shear testing should be in accordance with current industry standards only. This includes shearing the drill pipe with zero wellbore pressure and zero tension. There is a safety risk when shearing a drill pipe in the lab with high pressure in the wellbore and flowing conditions. Moreover, it is not practical to perform shear tests this way. The calculations consider the field application, taking into consideration the mechanical properties of the drill pipe and loading conditions. Effects of wellbore pressure on shear pressure should be calculated and be included in the test report. (iii) Was conducted at zero wellbore pressure and no tension or compression in the drill pipe.	(iii) Was conducted at zero wellbore pressure and no tension or compression in the drill pipe.

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§250.732(b)(1)(v)	(v) Ensures testing was performed on the outermost edges of the shearing blades of the positioning mechanism as required in § 250.734(d)(10);	Remove the section of "performed on the outermost edges" and is performed as required in 250.734(d)(16) which is within section § 250.734(d)(10). That allows 7 years for testing to be developed. Justification for performing this shear testing prior to the 7 years before the pipe centering requirement is in effect has not been made. (v) Ensures that the test demonstrates off-center pipe shearing capability within the time period referenced in § 250.734(a)(16)(i); Specify drill pipe for use in the well.	(v) Ensures that the test demonstrates off-center pipe shearing capability within the time period referenced in § 250.734(a)(16)(i);
§250.732(b)(1)(v)	(v) Demonstrates the shearing capacity of the BOP equipment to the physical and mechanical properties of the drill pipe; and	(v) Demonstrates the shearing capability of the BOP equipment to the physical and mechanical properties of the drill pipe to be used in the well; and	(v) Demonstrates the shearing capability of the BOP equipment relative to the physical and mechanical properties of the drill pipe to be used in the well; and
§250.732(b)(1)(v)	(v) Includes all testing results.	(v) Includes relevant testing results.	(v) Includes relevant testing results.
§250.732(b)(2)	You must submit verification and documentation related to: Pressure integrity testing and; That; (i) Shows that testing is conducted immediately after the shearing tests; (ii) Demonstrates that the equipment will seal at the rated working pressure of the BOP for 30 minutes; and (iii) Includes all test results.	Delete requirement for sealing pressure due to potential contamination offshore. Also, test pressure should be MAS9/MAWHPP, or the BOP of the sealing ram, whichever is lower.	You must submit verification and documentation related to: (2) Pressure integrity testing and; That: (i) Shows that pressure testing is conducted immediately after the shearing tests; (ii) demonstrates that the equipment will seal at the rated working pressure of the BOP, as per the time requirements in the relevant industry standards; and (iii) Includes relevant test results.
§250.732(b)(3)	You must submit verification and documentation related to: (3) Calculations. That: Include shearing and sealing pressures for all pipe to be used in the well including corrections for MAS9/MAWHPP.	BSR Verification Document – already doing. However, the 'sealing' component is an addition and we do not currently calculate the 'sealing' pressure for rams as this is more ambiguous and potentially misleading offshore.	You must submit verification and documentation related to: (3) Calculations. That: Include shearing pressures for all pipe to be used in the well including corrections for MAS9/MAWHPP, not to exceed the rated working pressure of the sealing preventer located directly above the uppermost shear ram.
§250.732(c)	(c) For wells in an HPHT environment, as defined by § 250.807(b), you must submit verification organization that the verification organization conducted a comprehensive review of the BOP system and related equipment you propose to use. You must provide the BSEE-approved verification organization access to any facility associated with the BOP system or related equipment during the review process. You must submit the verifications required by this paragraph to the appropriate District Manager before you begin any operations in an HPHT environment with the proposed equipment.	Change the wording of "access to any facility" to "access to documentation"	(c) For wells in an HPHT environment, as defined by § 250.807(b), you must submit verification by an independent third party that they 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 documentation associated with the BOP system or related equipment during the review process. You must submit the verifications required by this paragraph to the appropriate District Manager before you begin any operations in an HPHT environment with the proposed equipment.

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§250.732(c)(1)	You must submit: (1) Verification that the verification organization conducted a detailed review of the design package to ensure that all critical components and systems meet recognized engineering practices		You must submit: (1) Verification that the independent third party conducted a detailed review of the design package to ensure that all critical components and systems, as defined in API 53, meet recognized engineering practices
§250.732(c)(2)	You must submit: (2) Verification that the designs of individual components and the overall system have been proven in a testing process that demonstrates the performance and reliability of the equipment in a manner that is repeatable and reproducible. Including: (i) Identification of all reasonable potential modes of failure and (ii) Evaluation of the design verification tests. The design verification tests must assess the equipment for the identified potential modes of failure.	Recommend that the testing process refer to the appropriate validation testing required in industry specifications (e.g., API 16 A / 16 C / 16 D) There is no industry standard for the design of the overall system.	You must submit: (2) Verification that the designs of individual components have been proven in a testing process that demonstrates the performance and reliability of the equipment in a manner that is repeatable and reproducible as required in appropriate industry standards. Including: (i) Identification of all reasonable potential modes of failure, and (ii) Verification that the equipment designs have been assessed for the identified potential modes of failure. (iii) Evaluation of the design validation tests.
§250.732(c)(3)	You must submit: (3) Verification that the BOP equipment will perform as designed in the temperature, pressure, and environment that will be encountered and,		
§250.732(c)(4)	You must submit: (4) Verification that the fabrication, manufacture, and assembly of individual components and the overall system uses recognized engineering practices and quality control and assurance mechanisms. Including: For the quality control and assurance mechanisms, complete material and quality controls over all contractors, subcontractors, distributors, and suppliers at every stage in the fabrication, manufacture, and assembly process.	The phrase "complete material and quality controls over all contractors, subcontractors, distributors, and suppliers at every stage..." is overly broad and undefined. Complying with requirements for ALL contractors, subcontractors, distributors, and suppliers..... at EVERY stage..... would take many years to comply with.	You must submit: (4) Verification that the fabrication, manufacture, and assembly of individual components and the overall system uses recognized engineering practices and established quality control and assurance mechanisms. Including: The quality control, assurance requirements and material documentation specified by the industry standard(s) for the components and systems.
§250.732(d)	(d) Once every 12 months, you must submit a Mechanical Integrity Assessment Report for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility. This report must be completed by a BSEE-approved verification organization. You must submit this report to the Chief, Office of Regulatory Programs: Bureau of Safety and Environmental Enforcement: 45600 Woodland Road, Sterling, Virginia 20166. This report must include:	Recommend removing this section as all subparts are included in other existing or proposed CFR requirements, which are typically addressed on a frequency less than 12 months. As written, this would require considerable costs and resources with no additional benefits or reduction of risk.	Remove
§250.732(d)(1)	(1) A determination that the BOP stack and system meets or exceeds all BSEE regulatory requirements, industry standards incorporated into this subpart, and recognized engineering practices.	Recommend removing this requirement as it duplicates the APD requirements	Remove

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§250.732(d)(2)	(2) Verification that complete documentation of the equipment's service life exists that demonstrates that the BOP stack has not been compromised or damaged during previous service.	Recommend removing this requirement as it duplicates the APD requirements	Remove
§250.732(d)(3)	(3) A description of all inspection, repair and maintenance records reviewed, and verification that all repairs, replacement parts, and maintenance meet regulatory requirements, recognized engineering practices, and OEM specifications.	Recommend removing this requirement as it duplicates the APD requirements	Remove
§250.732(d)(4)	(4) A description of records reviewed related to any modifications to the equipment and verification that any such changes do not adversely affect the equipment's capability to perform as designed or invalidate test results.	Recommend removing this requirement as it duplicates the APD requirements	Remove
§250.732(d)(5)	(5) A description of the Safety and Environmental Management Systems (SEMS) plans reviewed related to assurance of quality and mechanical integrity of critical equipment and verification that the plans are comprehensive and fully implemented.	Recommend removing as it is currently covered in the current BSEE SEMS audits	Remove
§250.732(d)(6)	(6) Verification that the qualification and training of inspection, repair, and maintenance personnel for the BOP systems met recognized engineering practices and OEM requirements.	OEMs do not provide training requirements. Training and competency requirements addressed thru SEMS. Recognized engineering practices are addressed thru the applicable API standards and specifications.	Remove if not removed, change to and renumber: (6) would require that the personnel who maintain, inspect, or repair BOPs or other critical components meet the qualifications and training criteria specified by the equipment owner and that such maintenance, inspection, and repair be undertaken in accordance with API 53.
§250.732(d)(7)	(7) A description of all records reviewed covering OEM safety alerts, all failure reports, and verification that any design or maintenance issues have been completely identified and corrected.	Recommend this requirement is added to the APD and remove from this section	Remove
§250.732(d)(8)	(8) A comprehensive assessment of the overall system and verification that all components (including mechanical, hydraulic, electrical, and software) are compatible.	Recommend removing this requirement as it duplicates the APD requirements	Remove
§250.732(d)(9)	(9) Verification that documentation exists concerning the traceability of the fabrication, repair, and maintenance of all critical components.	Need to clarify the term "critical components." Recommend removing this requirement as it duplicates the APD requirements	Remove if not removed, change to and renumber: (9) Verification that documentation exists concerning the traceability of the fabrication, repair, and maintenance of all critical components as defined in API 53.
§250.732(d)(10)	(10) Verification of use of a formal maintenance tracking system to ensure that corrective maintenance and scheduled maintenance is implemented in a timely manner.	Recommend removing this requirement as it duplicates the APD requirements	Remove
§250.732(d)(11)	(11) Identification of gaps or deficiencies related to inspection and maintenance procedures and documentation, documentation of any deferred maintenance, and verification of the completion of corrective action plans.	Recommend removing this requirement as it duplicates the APD requirements	Remove

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.732(d)(12)	(12) Verification that any inspection, maintenance, or repair work met the manufacturer's design and material specifications.	Recommend removing this requirement as it duplicates the APD requirements	Remove
§250.732(d)(13)	(13) Verification of written procedures for operating the BOP stack and LMPP (including proper techniques to prevent accidental disconnection of these components) and minimum knowledge requirements for personnel authorized to operate and maintain BOP components.	Recommend removing this requirement as it duplicates the APD requirements	Remove
§250.732(d)(14)	(14) Recommendations, if any, for how to improve the fabrication, installation, operation, maintenance, inspection, and repair of the equipment.	Recommend removing as this requirement should be included in §250.730(c)	Remove
§250.732(e)	(e) You must make all documentation that supports the requirements of this section available to BSEE upon request.		Remove
§250.733(a)	(a) When you drill or conduct operations with a surface BOP stack, you must install the BOP system before drilling or conducting operations to deepen the well below the surface casing and after the well is deepened below the surface casing point. The surface BOP stack must include at least four remote-controlled, hydraulically operated BOPs, consisting of one annular BOP, one BOP equipped with blind-shear rams, and two BOPs equipped with pipe rams.	Too prescriptive. Ram placements and configurations should be established by the operator based on a risk assessment.	(a) When you drill or conduct operations with a surface BOP stack, you must install the BOP system before drilling or conducting operations to deepen the well below the surface casing and after the well is deepened below the surface casing point. A documented risk assessment shall be performed for all BOP arrangements to identify ram placements and configurations to be installed. The assessment shall include tapered strings, casings, completion equipment, test tools, etc.
§250.733(a)(1)	(1) The blind-shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that include heavy-weight pipe or collars), workstring, tubing, and any electric-, wire-, and slick-line that is in the hole and sealing the wellbore after shearing. If your blind-shear rams are unable to cut any electric-, wire-, or slick-line under MASP as defined for the operation and seal the wellbore, you must use an alternative cutting device capable of shearing the lines before closing the BOP. This device must be available on the rig floor during operations that require their use.	The preamble does not exclude TJ, BHA, etc components, but page 21523 of the notice does reference tool joints. Needs clarification	
§250.733(a)(2)	(2) The two BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, excluding the bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools.	See above regarding control lines	(2) For surface and subsea BOPs, the pipe and variable bore rams installed in the BOP stack must be capable of effectively closing and sealing on the tubular body of any drill pipe, workstring, and tubing (excluding control lines, flat packs, etc., where a risk assessment shall be used to identify additional mitigation measures) in the hole, as defined for the operation. Regulator settings will be adjusted above normal operating pressure as required.

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
\$250.733(b)	(b) If you plan to use a surface BOP on a floating production facility you must:		
\$250.733(b)(1)	(1) Follow the BOP requirements in §250.734(a)(1). You must comply with this requirement within 5 years from the publication of the final rule.	Refer to 250.734(a)(1) comments. To implement the changes on existing/producing facilities would involve shutdown and create greater risks than benefits	(1) Follow the BOP requirements in §250.734(a)(1). For floating production facilities, installed after the effective date of this rule, you must comply with this requirement. For existing floating production facilities risk assessments shall be submitted with the permit.
\$250.733(b)(2)	(2) Use a dual bore riser configuration, for risers installed after the effective date of this rule, before drilling or operating in any hole section or interval where hydrocarbons are, or may be, exposed to the well. The dual bore riser must meet the design requirements of API RP 2RD (as incorporated by reference in §250.198) including appropriate design for the most extreme anticipated operating and environmental conditions.	Clarification that existing facilities currently using single bore strings may continue to do so is needed In addition to dual casing (bore) TTRs, there are a few cases in the GoM where a single casing (bore) TTR concept were used. Suggest to stress dual barriers requirement for safety, which can be accommodated by either dual casing (bore) or split BOPs (surface BOP in combination with subsea isolation device). This is very important for future HPHT applications that we will be able to use "Dual Barrier" rather than Dual bore (single casing with shutdown valve).	(2) Use a dual bore riser configuration, for floating production facilities, installed after the effective date of this rule, before drilling or operating in any hole section or interval where hydrocarbons are, or may be, exposed to the well. The dual bore riser must meet the design requirements of API RP 2RD (as incorporated by reference in §250.198) including appropriate design for the most extreme anticipated operating and environmental conditions.
\$250.733(b)(2)(i)	(i) For a dual bore riser configuration, the annulus between the risers must be monitored during operations. You must describe in your APD or APM your annulus monitoring plan and how you will secure the well in the event a leak is detected.	Suggest to replace "Clarify that the annulus between the risers must be monitored during operations" with "pressure monitoring"	(j)For a dual bore riser configuration, pressure monitoring for annulus between outer casing and inner casing is required if outer casing is not designed with full rated wellhead tubing shut-in pressure. You must describe in your APD or APM your annulus monitoring plan and how you will secure the well in the event a leak is detected.
\$250.733(b)(2)(ii)	(ii) The inner riser for a dual riser configuration is subject to the requirements for testing the casing or liner at § 250.721.		
\$250.733(c)	(c) You must install separate side outlets on the BOP stack for the kill and choke lines. If your stack does not have side outlets, you must install a drilling spool with side outlets. The outlet valves must hold pressure from both directions.		
\$250.733(d)	(d) You must install a choke and a kill line on the BOP stack. You must equip each line with two full-bore, full-opening valves, one of which must be remote-controlled. On the kill line, you may install a check valve and a manual valve instead of the remote-controlled valve. To use this configuration, both manual valves must be readily accessible and you must install the check valve between the manual valves and the pump.		

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§250.733(c)	250.733(e) You must install hydraulically operated locks.	3 Months is not achievable for rigs that do not have hydraulically operated locks and the BOP controls system. After the operator locks remove the lock from the rig, they do not provide the reliability of a manual lock.	Delete requirement for surface BOPs and CWI for production: floating units and surface BOPs for HPHT wells.
§250.733(f)	250.733(f) For a surface BOP used in HPHT environments, if operations are suspended to make repairs to any part of the BOP system, you must stop operations at a safe downhole location. Before resuming operations you must: (1) Submit a revised APD or APM including documentation of the repairs and a certification from a BSEE-approved verification organization stating that they reviewed the repairs, and that the BOP is fit for service; and (2) Receive approval from the District Manager.		(f) For a surface BOP used in HPHT environments, if operations are suspended to make repairs to any part of the BOP system, you must stop operations at a safe downhole location. Before resuming operations you must: (1) Submit a revised APD or APM including documentation of the repairs and documentation (statement-of-fact) from an independent third party stating that they reviewed the repairs, and that the BOP is fit for service; and (2) Receive approval from the District Manager.
§250.734(a)	(a) When you drill or conduct operations with a subsea BOP system, you must install the BOP system before drilling to deepen the well below the surface casing or conducting operations if the well is deeper than the surface casing. Before drilling or conducting operations you must install a subsea BOP system before drilling or conducting operations below the conductor casing if proposed casing setting depths or local geology indicate the need. The following table outlines your requirements.		

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§250.734(a)(1)(i)-(ii)	When operating with a subsea BOP system, you must: (1) Have at least five remote-controlled, hydraulically operated BOPs; Additional requirements You must have at least one annular BOP, two BOPs equipped with pipe rams, and two BOPs equipped with shear rams. For the two shear ram requirement, you must comply with this requirement within 5 years from the publication of the final rule. (i) Both BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, excluding the bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools. (ii) Both shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that includes heavy-weight pipe or collars), workstring, tubing, appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric, wire, slick-line in the hole under MASP. At least one shear ram must be capable of sealing the wellbore after shearing under MASP conditions as defined for the operation. Any non-sealing shear rams must be installed below the sealing shear rams.	Any non-sealing shear ram must be installed below at least one sealing shear ram. The rule should not exclude non-hydraulic BOPs. The 5-year implementation needs to extend beyond the "two shear ram requirement" to the applicability of the whole section in order to allow for the introduction of technology to allow for the shearing of flat packs, slickline, etc. General comment needs to be developed on MASP – Not to exceed the rated pressure of the sealing preventer above the uppermost shear ram. Discussion on use of MAWHP vs. MASP for both subsea and surface. MASP is not the appropriate term, as used by BSEE, for subsea.	You must comply with this requirement within 5 years from the publication of the final rule. When operating with a subsea BOP system, you must: (1) Have at least five remote-controlled, hydraulically operated BOPs; Additional requirements You must have at least one annular BOP, two BOPs equipped with pipe rams, and two BOPs equipped with shear rams. (i) Both BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MAWHP, not to exceed the rated pressure of the sealing preventer above the uppermost shear ram, as defined for the operation, excluding the bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools. (ii) Both shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that includes heavy-weight pipe or collars), workstring, tubing, appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric, wire, slick-line in the hole, under MAWHP, but not to exceed the rated pressure of the sealing preventer above the uppermost shear ram. At least one shear ram must be capable of sealing the wellbore after shearing under MAWHP conditions as defined for the operation. Any non-sealing shear rams must be installed below at least one set of the sealing shear rams.
§250.734(a)(2)	When operating with a subsea BOP system, you must: (2) Have an operable dual-pod control system to ensure proper and independent operation of the BOP system;	Dual pod" is too prescriptive and may restrict alternatives. The objective is redundancy, which is already adequately addressed by API 53.	When operating with a subsea BOP system, you must: (2) Have a redundant control system to ensure proper and independent operation of the BOP system;

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.734(a)(3)	<p>When operating with a subsea BOP system, you must: (3) Have the accumulator capacity located subsea, to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface.</p> <p>Additional requirements The accumulator capacity must: (i) Function each required shear ram, choke and kill side outlet valves, one pipe ram, and disconnect the LMRP, (ii) Have the capability of delivering fluid to each ROV function i.e., flying leads. (iii) Have dedicated independent bottles for the autoshear, deadman, and EDS systems. (iv) Perform under MASP conditions as defined for the operation.</p>	<p>There may be engineering changes needed for compliance. 90-day implementation may not be feasible.</p>	<p>When operating with a subsea BOP system, you must: (3) Have the accumulator capacity, to provide fast closure of the BOP components during normal operation and EDS. Further, have the accumulator capacity located subsea, to provide closure of the deadman and autoshear within the response times specified in API 53 in case of a loss of the power fluid connection to the surface. Additional requirements: Within 5 years of the publication of the final rule, the subsea accumulator capacity must be sufficient to: (i) Close each required shear ram. (ii) Have accumulator bottles that are dedicated to the emergency systems for both the autoshear and deadman.</p>
§250.734(a)(4)	<p>When operating with a subsea BOP system, you must: (4) Have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention capability; Additional requirements: The ROV must be capable of performing critical functions including opening and closing each shear ram, choke and kill side outlet valves, all pipe rams, and LMRP disconnect under MASP conditions as defined for the operation. The ROV panels on the BOP and LMRP must be compliant with API RP 17H (as incorporated by reference in § 250.198).</p>	<p>This is a major change for some rigs as it exceeds the requirements of API 53.</p> <p>This is a requirement that is more germane to the LMRP than the ROV.</p> <p>Provision should be made to allow actual demonstration of stabbing into an ROV intervention panel on a subsea stack. E.g., add "or equivalent" at end of sentence.</p> <p>It is not clear if this is intended to require 24/7 ROV coverage.</p> <p>We interpret the language of: "The ROV must be capable . . ." in the same manner that was discussed and included in API 53.</p>	<p>When operating with a subsea BOP system, you must: (4) Have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention capability;</p> <p>The ROV must be capable of performing critical functions, as defined in API 53 7.4.16.1.1, under MAWHP conditions as defined for the operation.</p> <p>The ROV panels on the BOP and LMRP must be compliant with API RP 17H (as incorporated by reference in § 250.198).</p>

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.734(a)(5)	<p>When operating with a subsea BOP system, you must: (5) Maintain an ROV and have a trained ROV crew on each rig unit on a continuous basis once BOP deployment has been initiated from the rig until recovered to the surface. The crew must examine all ROV related well control equipment (both surface and subsea) to ensure that it is properly maintained and capable of shutting in the well during emergency operations;</p> <p>Additional requirements: The crew must be trained in the operation of the ROV. The training must include simulator training on stabbing into an ROV intervention panel on a subsea BOP stack. The ROV crew must be in communication with designated rig personnel who are knowledgeable about the BOP's capabilities.</p>		<p>When operating with a subsea BOP system, you must: (5) Maintain an ROV and have a trained ROV crew on each rig unit on a continuous basis once BOP deployment has been initiated from the rig until recovered to the surface. The ROV crew must be familiar with all ROV related equipment (both surface and subsea) to ensure that it is properly maintained and capable of carrying out appropriate tasks during emergency operations; Additional requirements: The crew must be trained in the operation of the ROV. The training must include competence training on stabbing into an ROV intervention panel and operating the type(s) of ROV valves that are mounted on the BOP stack. The ROV crew must be able to be in constant communication with designated rig personnel who are knowledgeable about the BOP's capabilities whenever the ROV is deployed to the BOP stack.</p>
§250.734(a)(6)	<p>When operating with a subsea BOP system, you must: (6) Provide autoshear, deadman, and EDS systems for dynamically positioned rigs; provide autoshear and deadman systems for moored rigs; Additional requirements: (i) Autoshear system means a safety system that is designed to automatically shut-in the wellbore in the event of a disconnect of the LMRP. This is considered a rapid discharge system. (ii) Deadman system means a safety system that is designed to automatically shut-in the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods. This is considered a rapid discharge system. (iii) Emergency Disconnect Sequence (EDS) system means a safety system that is designed to be manually activated to shut-in the wellbore and disconnect the LMRP in the event of an emergency situation. This is considered a rapid discharge system. (iv) Each emergency function must close at a minimum, two shear rams in sequence and be capable of performing their expected shearing and sealing action under MASP conditions as defined for the operation. (v) Your sequencing must allow a sufficient delay for closing the upper shear ram after beginning closure of the lower shear ram to provide for maximum shearing efficiency. (vi) The control system for the emergency functions must be a fail-safe design, and the logic must provide for the subsequent step to be independent from the previous step having to be completed.</p>	<p>Issue associated with timing sequence of shears.</p> <p>Emergency functions should be operations specific</p> <p>Separate EDS from other deadman and autoshear</p> <p>Clarifying intent of expected shearing and sealing expectation</p> <p>An operational risk assessment determines the optimum emergency sequence for the specific operation to be performed. And this is too prescriptive a requirement in the shearing sequential requirement (there are many differences between an EDS selected sequence and the use of the deadman/autoshear). The prescribed method in the proposed rule may not be the safest method to undertake.</p> <p>Changing over to a timing circuit for DM/AS systems that would be failsafe type would require engineering and lead times of new equipment to be manufactured, installed and tested. If this is the intent, it cannot be accomplished within 90 days of publication of the final rule. Three years would be appropriate.</p>	<p>When operating with a subsea BOP system, you must: (6) Provide autoshear, and deadman for moored and dynamically positioned; Additional requirements: (i) Autoshear system means a safety system that is designed to automatically shut-in the wellbore in the event of a disconnect of the LMRP. This is considered a rapid discharge system. (ii) Deadman system means a safety system that is designed to automatically shut-in the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods. This is considered a rapid discharge system. (iii) Emergency Disconnect Sequence (EDS) system means a safety system that is designed to be manually activated to disconnect the LMRP in the event of an emergency situation. This is considered a rapid discharge system. (iv) The Deadman Autoshear system must be capable of shearing the body of the drill pipe in use and then sealing the well.</p>

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.734(a)(7)	730.734(a)(7) When operating with a subsea BOP system, you must: (7) Demonstrate that any acoustic control system will function in the proposed environment and conditions; Additional requirements: If you choose to install an acoustic control system in addition to the autoshear, deadman, and EDS requirements, you must demonstrate to the District Manager, as part of the information submitted under § 250.731, that the acoustic system will function in the proposed environment and conditions. The District Manager may require additional information.	There could be unintended consequences. If a failure of the acoustic system results in a mandatory stack pull for repairs, then industry will be encouraged to remove the acoustic system. As per proposed section 250.738(e) acoustic systems will be treated as a redundant system as described in the text.	When operating with a subsea BOP system, you must: (7) Demonstrate that any acoustic control system will function in the proposed environment and conditions or risk assess continuation without the acoustic system; Additional requirements: If you choose to install an acoustic control system in addition to the autoshear, deadman, and EDS requirements, you must demonstrate to the District Manager, as part of the information submitted under § 250.731, that the acoustic system will function in the proposed environment and conditions. The District Manager may require additional information.
§250.734(a)(8)	When operating with a subsea BOP system, you must: (8) Have operational or physical barrier(s) on BOP control panels to prevent accidental disconnect functions; Additional requirements: Incorporate enable buttons on control panels to ensure two-handed operation for all critical functions.		When operating with a subsea BOP system, you must: (8) Have operational or physical barrier(s) on BOP control panels to prevent accidental disconnect functions; Additional requirements: Incorporate two-handed operation for all critical functions.
§250.734(a)(9)	When operating with a subsea BOP system, you must: (9) Clearly label all control panels for the subsea BOP system; Additional requirements: Label other BOP control panels such as hydraulic control panel.		Accept proposed text
§250.734(a)(10)	When operating with a subsea BOP system, you must: (10) Develop and use a management system for operating the BOP system, including the prevention of accidental or unplanned disconnects of the system; Additional requirements: The management system must include written procedures for operating the BOP stack and LMRP (including proper techniques to prevent accidental disconnection of these components) and minimum knowledge requirements for personnel authorized to operate and maintain BOP components.		Accept proposed text
§250.734(a)(11)	When operating with a subsea BOP system, you must: (11) Establish minimum requirements for personnel authorized to operate critical BOP equipment; Additional requirements: Personnel must have: (i) Training in deepwater well-control theory and practice according to the requirements of Subpart O; and (ii) A comprehensive knowledge of BOP hardware and control systems.	It is not clear if this is intended to impose requirements over and above those of the existing requirements of Subparts O and S. Clarification from BSEE is needed. If additional requirements are being imposed, implementation within 90-days of promulgation of the final rule is not feasible	

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.734(a)(12)	When operating with a subsea BOP system, you must: (12) before removing the mainline riser, displace the fluid in the riser with seawater. Additional requirements: You must maintain sufficient hydrostatic pressure in the well to compensate for the reduction in pressure and to maintain a safe and controlled well condition. You must follow the requirements of § 250.720(b).		When operating with a subsea BOP system, you must: (12) before planned removal of mainline riser, displace the fluid in the riser with seawater. Additional requirements: You must maintain sufficient hydrostatic pressure or take other suitable precautions to compensate for the reduction in pressure and to maintain a safe and controlled well condition. You must follow the requirements of § 250.720(b).
§250.734(a)(13)	When operating with a subsea BOP system, you must: (13) install the BOP stack in a well cellar when in an ice-scour area; Additional requirements: Your well cellar must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.	Change to read "lower BOP stack"	When operating with a subsea BOP system, you must: (13) install the lower BOP stack in a well cellar when in an ice-scour area; Additional requirements: Your well cellar must be deep enough to ensure that the top of the lower BOP stack is below the deepest probable ice-scour depth.
§250.734(a)(14)	When operating with a subsea BOP system, you must: (14) install at least two side outlets for a choke line and two side outlets for a kill line; Additional requirements: (i) If your stack does not have two side outlets for a choke line and two side outlets for a kill line, you must install a side outlet for a choke line and a side outlet for a kill line. The valves must hold pressure from both directions and must be remote-controlled. (iv) You must install a side outlet below each sealing shear ram. You may have a pipe ram or rams between the shearing ram and side outlet.	changed layout of paragraph and "direct tang" Correct "chock line"	When operating with a subsea BOP system, you must: (14) install at least two side outlets for a choke line and two side outlets for a kill line; Additional requirements: (i) If your stack does not have two side outlets for a choke line and two side outlets for a kill line, you must install a side outlet for a choke line and a side outlet for a kill line. The valves must hold pressure from both directions and must be remote-controlled. (iv) You must install a side outlet below each sealing shear ram. You may have a pipe ram or rams between the shearing ram and side outlet.

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.734(a)(15)	250.734(a)(15) When operating with a subsea BOP system, you must: (15) Install a gas bleed line with two valves for annular preventer; Additional requirements: (i) The valves must hold pressure from both directions; (ii) If you have dual annulars, where one annular is on the LMRP and one annular is on the lower BOP stack, you must install a gas bleed line on each annular.	<p>Many existing annular BOPs do not have a side outlet.</p> <p>Every valve and every outlet we add to the BOPs increases leak paths and reliability concerns.</p> <p>You must have the capability to circulate below each annular.</p> <p>This rule encourages removal of well control equipment from the BOP stack resulting in an unintentional consequence of removal of lower BOP and installation of a drilling spool</p> <p>Some BOP stacks, the lower annual is integral to the stack frame and would not permit installation of gas bleed valve or line without extensive modification to the vessel or stack.</p>	When operating with a subsea BOP system, you must: (15) Install a gas bleed line with two valves under the annular preventer; Additional requirements: (i) The valves must hold pressure from both directions; (ii) If you have two annulars, where one annular is on the LMRP and one annular is on the lower BOP stack, and your BOP stack was manufactured after the effective date of this regulation, you must have the capability to circulate below each annular.
§250.734(a)(16)	250.734(a)(16) When operating with a subsea BOP system, you must: (16) Use a BOP system that has the following mechanisms and capabilities: Additional requirements: (i) A mechanism coupled with each shear ram to position the entire pipe, including connection, completely within the area of the shearing blade and ensure shearing will occur any time the shear rams are activated. This mechanism cannot be another ram BOP or annular preventer, but you may use those during a planned shear. You must install this mechanism within 7 years from the publication of the final rule; (ii) The ability to mitigate compression of the pipe stub between the shearing rams when both shear rams are closed; (iii) If your control pods contain a subsea electronic module with batteries, a mechanism for personnel on the rig to monitor the state of change of the subsea electronic module batteries in the BOP control pods.		When operating with a subsea BOP system, you must: (16) Use a BOP system that has the following mechanisms and capabilities: Additional requirements: (i) A mechanism coupled with each shear ram to position the entire drill pipe, including connection, completely within the area of the shearing blade and ensure shearing will occur any time the shear rams are activated. This mechanism cannot be another ram BOP or annular preventer, but you may use those during a planned shear. You must install this mechanism within 7 years from the publication of the final rule; (ii) The ability to accept the pipe stub between the shearing rams when both shear rams are closed; (iii) If your control pods contain a subsea electronic module with batteries, a mechanism for personnel on the rig to monitor the state of change of the subsea electronic module batteries in the BOP control pods.

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.734(b)	(b) If operations are suspended to make repairs to any part of the subsea BOP system, you must stop operations at a safe downhole location. Before resuming operations you must: (1) Submit a revised permit with a verification report from a BSEE-approved verification organization documenting the repairs and that the BOP is fit for service; (2) Perform a new BOP test in accordance with §§ 250.737 and 250.738 upon relatch including deadman and ROV intervention; and (3) Receive approval from the District Manager.	When only the LMRP is retrieved, it is not necessary to re-test deadman or lower stack ROV intervention functions. Broad definition of "BOP system" and undefined "suspension of operations" needs to be clarified in order to limit adverse impact. Present wording leads to unnecessary deadman tests. Conflicts with API 53. Only the affected components are required to be tested.	(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) Perform a new BOP test in accordance with §§ 250.737 and 250.738 upon relatch including any functions affected during the repair; and (3) Receive approval from the District Manager.
§250.734(c)	(c) If you plan to drill a new well with a subsea BOP, you do not need to submit with your APD the verifications required by this subpart for the open water drilling operation. Before drilling out the surface casing, you must submit for approval a revised APD, including the verifications required in this subpart.		Accept proposed text
§250.735	All BOP systems must include the following associated systems and related equipment:		

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§250.735(f)	<p>(a) A surface accumulator system that provides 1.5 times the volume of fluid capacity necessary to close and hold closed all components against the wellbore pressure in the system must be capable of operating in the event of a failure of the system. You must be able to operate all BOP functions without assistance from a charging system, with the blind shear ram being the last in the sequence, and still have enough pressure to shear pipe and seal the well with a minimum pressure of 200 psi remaining on the bottles above the precharge pressure. If you supply the accumulator regulators by rig air and do not have a secondary source of preumatic supply, you must equip the regulators with manual overrides or other devices to ensure capability of hydraulic operations if rig air is lost;</p>	<p>Industry SMEs including OEM, Operator, Contractor, Contractor and rig designers collaborated to produce API 53 design and testing requirements for the industry. The industry has agreed to amend the standard to reflect how gases behave at these temperatures and pressures. The BSEE proposed requirement contradicts the requirements of API 53. It is not achievable, and is sufficiently ambiguous that industry SMEs cannot achieve a common understanding of the intent. It is not just the direct impact of the additional number of accumulator bottles, but the associated changes to pumping systems and storage tanks. For example, some SMEs concluded that the proposed requirement to provide 1.5 times the volume of fluid capacity necessary to close and hold closed all BOP components against MWSP could result in the elimination of some BOP components from the system. Industry data reflecting rigs in service (see attached) demonstrate the magnitude of the changes to BOP and associated equipment which would be required to achieve compliance with the BSEE proposed rule. This additional equipment would be accompanied by additional maintenance burdens and potentially render the systems less reliable. Equipment owners have been asked to submit details of the cost impacts for their individual rigs, recognizing that such information is commercially sensitive and will rely on BSEE's statement that they will protect such information from disclosure. For certain older rigs, the additional requirements could force the removal of the rigs from service in the US market (i.e. the cost of upgrading these rigs into the US market is prohibitive not feasible). Industry consensus is that the punitive requirements do nothing to enhance safety or increase reliability.</p>	<p>Delete this paragraph. Sections 6.5.6.2 and 7.6.8.2 of API 53 adequately address these concerns. API 53 is incorporated by reference</p>

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.735(b)	(b) An automatic backup to the primary accumulator-charging system. The power source must be independent from the power source for the primary accumulator-charging system. The independent power source must possess sufficient capability to close and hold closed all BOP components under MASP conditions as defined for the operation;		(b) A minimum of two pump systems are required; a pump system may consist of one or more pumps. Each pump system shall have an independent power source. These pump systems shall be connected such that the loss of any one power source does not impair the operation of the other pump systems. At least one pump system shall be available and operational at all times system.
§250.735(c)	(c) At least two full BOP control stations. One station must be on the rig floor. You must locate the other station in a readily accessible location away from the rig floor;		Accept proposed text
§250.735(d)	(d) The choke line(s) installed above the bottom well-control ram;		Accept proposed text
§250.735(e)	(e) The kill line that may be installed below the bottom ram, but it must be installed beneath at least one pipe ram;		(e) The lowermost line connected to the BOP stack shall be identified as the kill line. For BOPs that have lines installed on each side of the outlet below the lowermost well control ram, either may be designated as a choke or kill line.
§250.735(f)	(f) A fill-up line above the uppermost BOP;		(f) A fill-up line usually connected to the diverter housing, or bell nipple, above the BOPs to facilitate adding drilling fluid to the hole, at atmospheric pressure.
§250.735(g)	(g) Hydraulically operated locking devices installed on the sealing ram-type BOPs; and	Differentiate between surface and subsea BOPs. Refer back to API 53 in order to minimized effect for surface stacks.	(g) All sealing ram-type preventers shall be equipped with locking devices. Surface stacks can be equipped with manual locks and subsea stacks should be equipped with hydraulic locks.
§250.735(h)	(h) A wellhead assembly with a rated working pressure that exceeds the maximum anticipated wellhead pressure.		Accept proposed text
§250.736(a)	(a) Your BOP system must include a choke manifold that is suitable for the anticipated surface pressures, anticipated methods of well-control, the surrounding environment, and the corrosiveness, volume, and abrasiveness of drilling fluids and well fluids that you may encounter.		Accept proposed text
§250.736(b)	(b) Choke manifold components must have a rated working pressure at least as great as the rated working pressure of the ram BOPs. If your choke manifold has buffer tanks downstream of choke assemblies, you must install isolation valves on any bleed lines.		(b) Choke manifold components upstream of the first valve behind the chokes must have a rated working pressure at least as great as the rated working pressure of the ram BOPs. Components downstream of the first valve behind the chokes must have a rated working pressure at least as great as the rated working pressure of the annular BOP. You must install isolation valves on any bleed lines.

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.739(C)	(c) Valves, pipes, flexible steel hoses, and other fittings upstream of the choke manifold must have a rated working pressure at least as great as the rated working pressure of their ram BOP's.		Accept proposed text

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.736(d)	<p>(d) You must use the following BOP equipment with a rated working pressure and temperature of at least as great as the working pressure and temperature of the ram BOP during all operations: (1) A kelly valve installed below the swivel (upper kelly valve); (2) A kelly valve installed at the bottom of the kelly (lower kelly valve). You must be able to strip the lower kelly valve through the BOP stack; (3) If you operate with a mud motor and use drill pipe instead of a kelly, one kelly valve installed above, and one strippable kelly valve installed below, the joint of pipe used in place of a kelly; (4) On a top-drive system equipped with a remote-controlled valve, a strippable kelly-type valve installed below the remote-controlled valve; (5) An inside BOP in the open position located on the rig floor. You must be able to install an inside BOP for each size connection in the pipe; (6) A drill string safety valve in the open position located on the rig floor. You must have a drill-string safety valve available for each size connection in the pipe; (7) When running casing, a safety valve in the open position available on the rig floor to fit the casing string being run in the hole; (8) All required manual and remote-controlled kelly valves, drill-string safety valves, and comparable-type valves (i.e., kelly-type valve in a top-drive system) that are essentially full opening; and (9) A wrench to fit each manual valve. Each wrench must be readily accessible to the drilling crew.</p>	<p>Issue is "rated working pressure and temperature of at least as great as the working pressure and temperature of the ram BOP during all operations"</p> <p>(d) Interpretation of this requirement leads one to believe that a kelly and associated kelly equipment is required. Kelly's are seldom used in OCS jurisdiction and has limited applications.</p> <p>(3) This is not a gap in any industry documents. This methodology is obsolete and has been addressed with MMS in the past. This practice was discontinued in the 80's after the proven use and operation of top drives. This requirement is not a best practice.</p> <p>(4) More specific than API 53 and API 53 should be referenced as this proposed language is not well presented.</p> <p>(5), (6), (7), & (8) In compliance with SC16 documents.</p> <p>55</p>	<p>(d) If you use the following BOP equipment it must have a rated working pressure and temperature of at least as great as the working pressure and temperature of the ram BOP during all operations: (1) A kelly valve installed below the swivel (upper kelly valve); (2) A kelly valve installed at the bottom of the kelly (lower kelly valve). You must be able to strip the lower kelly valve through the BOP stack; (3) If you operate with a mud motor and use drill pipe instead of a kelly, one kelly valve installed above, and one strippable kelly valve installed below, the joint of pipe used in place of a kelly; (4) On a top-drive system equipped with two ball valves, the upper valve is air or hydraulically operated and controlled at the driller's console and the lower valve is a standard ball valve (sometimes referred to as a safety valve) and is manually operated, usually by means of a large hexagonal wrench. If necessary, to prevent or stop flow up the drill pipe during tripping operations, a separate drill pipe valve should be used rather than either of the two top drive valves. However, flow up the pipe might prevent stabbing this valve. In that case, the top drive with its valves can be used, keeping in mind the following cautions:</p> <p>(a) once the top drive's manual valve is installed, closed, and the top drive disconnected, a crossover may be required to install an inside BOP on top of the manual valve;</p> <p>(b) most top drive valves cannot be stripped into 7-5/8" or smaller casing;</p> <p>(c) once the top drive's manual valve is disconnected from the top drive, another valve and crossover may be required. (5) An inside BOP in the open position located on the rig floor. You must be able to install an inside BOP for each size connection in the pipe; (6) A drill string safety valve in the open position located on the rig floor. You must have a drill-string safety valve available for each size connection in the pipe; (7) When running casing, a safety valve in the open position available on the rig floor to fit the casing string being run in the hole; (8) All required manual and remote-controlled kelly valves, drill-string safety valves, and comparable-type valves (i.e., kelly-type valve in a top-drive system) that are essentially full opening; and (9) A wrench to fit each manual valve. Each wrench must be readily accessible to the drilling crew.</p>

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.737	Your BOP system (this includes the choke manifold, Kelly valves, inside BOP, and drill string safety valve) must meet the following testing requirements:		Accept proposed text.
§250.737(a)(1-2)	(a) Pressure test frequency. You must pressure test your BOP system: (1) When installed; (2) Before 14 days have elapsed since your last BOP pressure test, or 30 days since your last blind-shear ram BOP pressure test. You must begin to test your BOP system before midnight on the 14th day (or 30th day for your blind-shear rams) following the conclusion of the previous test;	(2) For surface systems, a gap has been noted and is being addressed in API 53 - 5th addition or addendum. To look more like the subsea section of the document (Blind shear rams only). Adjusting language to recognize a 21 day BOP test interval (alignment with § 53).	(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;
§250.737(a)(3)	(3) Before drilling out each string of casing or a liner. You may omit this pressure test requirement if you did not remove the BOP stack to run the casing string or liner, the required BOP test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test, and the time elapsed between tests has not exceeded 14 days (or 30 days for blind-shear rams). You must indicate in your APD which casing strings and liners meet these criteria;		(3) Before drilling out each string of casing or a liner. You may omit this pressure test requirement if you did not remove the BOP stack to run the casing string or liner, the required BOP test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test, and the time elapsed between tests has not exceeded 21 days (or 30 days for blind-shear rams). You must indicate in your APD which casing strings and liners meet these criteria;
§250.737(a)(4)	(4) The District Manager may require more frequent testing if conditions or your BOP performance warrants.		Accept proposed text.
§250.737(b)	(b) Pressure test procedures. When you pressure test the BOP system, you must conduct a low-pressure test and a high-pressure test for each BOP component. You must begin each test by conducting the low-pressure test then transition to the high-pressure test. Each individual pressure test must hold pressure long enough to demonstrate the tested component(s) holds the required pressure. The table in this paragraph outlines your pressure test requirements.		Accept proposed text. Adjust table if needed to recognize a 21 day test interval.
§250.737(b)(1)	You must conduct a...: (1) Low-pressure test... According to the following procedures...: All low-pressure tests must be between 250 and 350 psi. Any initial pressure above 350 psi must be bled back to a pressure between 250 and 350 psi before starting the test. If the initial pressure exceeds 500 psi, you must bleed back to zero and reinitiate the test.		Accept proposed text.

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.737(b)(2)	You must conduct a...: (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. According to the following procedures... : The high-pressure test must equal the rated working pressure of the equipment or be 500 psi greater than your calculated MASP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP plus 500 psi, the District Manager must have approved those test pressures in your APD.	Testing to pressure lesser of MASP but NTE rated working pressure of the equipment. Recommend that the proposed WCR follow the same references as AP153, w.r.t. MASP and MAWHP and how they are applicable relative to operations. This WCR does not split between initial and subsequent testing. For subsea there is stump, initial and subsequent that all have different test pressures. Potential for Unintended Consequences and failure to comply between this requirement and SC16 documents	You must conduct a...: (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. According to the following procedures...: The high-pressure test must equal the lesser of the rated working pressure of the equipment or be 500 psi greater than your calculated MASP/MAWHP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP/MAWHP plus 500 psi, the District Manager must have approved those test pressures in your APD.
§250.737(b)(3)	You must conduct a...: (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. According to the following procedures... : The high pressure test must equal 70 percent of the rated working pressure of the equipment or be 500 psi greater than your calculated MASP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP plus 500 psi, the District Manager must have approved those test pressures in your APD.	This is confusing when trying to mix surface and subsea into one single requirement. Reference API 53 in its entirety. The ability to define these testing requirements in the APD would seem suitable.	You must conduct a...: (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. According to the following procedures...: The high-pressure test must equal the lesser of the rated working pressure of the equipment or be 500 psi greater than your calculated MASP/MAWHP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP/MAWHP plus 500 psi, the District Manager must have approved those test pressures in your APD
§250.737(c)	(c) Duration of pressure test. Each test must hold the required pressure for 5 minutes, which must be recorded on a chart not exceeding 4 hours. However, for surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable if recorded on a chart not exceeding 4 hours, or on a digital recorder. The recorded test pressures must be within the middle half of the chart range, i.e., cannot be within the lower or upper one-fourth of the chart range. If the equipment does not hold the required pressure during a test, you must correct the problem and retest the affected component(s).		(c) Duration of pressure test. Each test must hold the required pressure for 5 minutes, which must be recorded on a chart not exceeding 4 hours. However, for surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable if recorded on a chart not exceeding 4 hours, or on a digital recorder. This requirement is to be met within twelve months of publication of the final rule.
§250.737(d)	(d) Additional test requirements. You must meet the following additional BOP testing requirements:		

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.737(d)(1)	You must...: (1) Follow the testing requirements of API Standard 53 (as incorporated in § 250.198). Additional requirements...If there is a conflict between API Standard 53 testing requirements and this section, you must follow the requirements of this section.	Recommend using industry standards (API 53) rather than specifying additional requirements.	You must: 1) Follow the testing requirements of API Standard 53 (as incorporated in § 250.198).
§250.737(d)(2)	You must...: (2) Use water to test a surface BOP system. Additional requirements... (i) You must submit test procedures with your APD or APM for District Manager approval. (ii) Contact the District Manager at least 72 hours prior to beginning the test to allow BSEE representative(s) to witness testing. If BSEE representative(s) are unable to witness testing, you must provide the test results to the appropriate District Manager within 72 hours after completion of the tests.	Experience shows that use of water may not be an appropriate safe practice. Suggest alternative language to select test fluid appropriate for the well conditions. Addressed in API 53 Only the initial or stump test required the use of water. After that point, the use of mud is acceptable. A loss of hydrostatic could result in a well control incident. (See PSA alerts). Clarifications are being addressed in API 53 5th edition. WCR does not break down the water testing requirements as API 53 will.	You must... (2) Use water to test a surface BOP system. Additional requirements... (i) You must submit test procedures with your APD or APM for District Manager approval. (ii) Contact the District Manager at least 72 hours prior to beginning the test to allow BSEE representative(s) to witness testing. If BSEE representative(s) are unable to witness testing, you must provide the test results to the appropriate District Manager within 72 hours after completion of the tests.
§250.737(d)(3)(i-v)	You must... (3) Stump test a subsea BOP system before installation. Additional requirements... (i) You must use water to conduct this test. You may use drilling fluids to conduct subsequent tests of a subsea BOP system. (ii) You must submit test procedures with your APD or APM for District Manager approval. (iii) Contact the District Manager at least 72 hours prior to beginning the stump test to allow BSEE representative(s) to witness testing. If BSEE representative(s) are unable to witness testing, you must provide the test results to the appropriate District Manager within 72 hours after completion of the tests. (iv) You must test and verify closure of all ROV intervention functions on your subsea BOP stack during the stump test. (v) You must follow (b) and (c) of this section.		You must... (3) Carry out a pre-deployment test of your subsea BOP system before installation. Additional requirements... (i) You must use water to conduct this test. You may use drilling fluids to conduct subsequent tests of a subsea BOP system. (ii) You must submit test procedures with your APD or APM for District Manager approval. (iii) You must test and verify closure of the following critical ROV intervention functions: (1) shear ram close, (2) one pipe ram close, and (3) LMRP unlock/unlatch intervention functions on your subsea BOP stack during the stump test. (iv) You must follow (b) and (c) of this section.
§250.737(d)(4)(i-iv)	You must... (4) Perform an initial subsea BOP test. Additional requirements... (i) You must perform the initial subsea BOP test on the seafloor within 30 days of the stump test. (ii) You must submit test procedures with your APD or APM for District Manager approval. (iii) You must pressure test well-control rams according to (b) and (c) of this section. (iv) You must notify the District Manager at least 72 hours prior to beginning the initial subsea test for the BOP system to allow BSEE representative(s) to witness testing.	(i) Conflicts with API 53. There is not a timing requirement between stump testing and installation. This is a risk based operation and is determined by the operator and equipment owner.	You must... (4) Perform a pre-deployment test before running the subsea stack (i) Perform an initial subsea BOP test upon landing on the wellhead. (ii) You must perform the subsequent subsea tests at intervals of no more than 21 days from the initial subsea test. (iii) You must submit test procedures with your APD or APM for District Manager approval. (iv) You must pressure test well-control rams according to (b) and (c) of this section.

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.737(d)(4)(v)	(v) You must test and verify closure of at least one set of rams during the initial subsea test through a ROV hot stab. You must pressure test the selected rams according to (b) and (c) of this section.	Conflicts with API 53, specifies blind shear ram or pipe rams to be functioned by ROV but, not pressure tested and only annually. No plans to change API 53 language.	(v) You must test and verify closure of at least a blind shear ram or a pipe ram annually through a ROV hot stab. The selected ram should close in 45 seconds or less (minimum time to secure the wellbore, does not include functions after the well has been secured).
§250.737(d)(5)	You must...: (5) Alternate tests between control stations and pods. Additional requirements...(i) For two complete BOP control stations: (A) Designate a primary and secondary station, and both stations must be function-tested weekly, (B) The control station used for the pressure test must be alternated between pressure tests, and (C) For a subsea BOP, the pods must be rotated between control stations during weekly function testing, and the pod used for pressure testing must be alternated between pressure tests. (ii) Any additional control stations must be function tested every 14 days.	(B) API 53 permits the pressure test to be recognized as a function test. (C) Conflicts with API 53. Cannot achieve this when implementing A & B above. Interpretation is that both pods from both stations is being the requirement. Industry does not accept this proposal. (ii) Conflicts with API 53. Example: if a remote station is only provided with an EDS function then this becomes an endangerment to personnel and the environment.	You must...: (5) function test all well control components, excluding hydraulic connectors and shear rams, to verify the component's intended operation at least once every seven days or as operations allow. Pressure tests qualify as function tests. Casing and blind shear rams shall be function tested at least once every twenty-one days. (A) Designate a primary and secondary station. Prior to deployment, all control stations and both pods shall be function tested. The operability of individual control stations shall be confirmed. Subsequent function tests shall be performed from one BOP control station and one pod weekly. These tests shall rotate through both pods and the two designated control panels. So that one pod and one panel are tested every week but that the same combinations are not tested in consecutive weeks.
§250.737(d)(6)	You must...: (6) Pressure test variable bore-pipe ram BOPs against the largest and smallest sizes of pipe in use, excluding the bottom hole assembly that includes heavy-weight pipe or collars and bottom-hole tools.	This is in conflict with API 53 in that both sizes are required for testing whereas, API 53 only requires the smaller pipe on subsequent testing and both sizes on stump testing.	You must...: (6) During pre-deployment (stump) testing, pressure test variable bore-pipe ram BOPs against the largest and smallest sizes of pipe in use, excluding drill collars and bottom-hole tools; during subsequent testing, pressure test variable bore-pipe ram BOPs against the smallest size drill pipe in use, excluding drill collars and bottom-hole tools.
§250.737(d)(7)	You must...: (7) Pressure test annular type BOPs against the smallest pipe in use.	Somewhat in compliance with API 53. However, for stump testing both sizes are required testing.	You must...: (7) For pre-deployment BOP test (stump test) the annular type BOPs shall be pressure tested against the largest and smallest drill pipe in use. For all subsea pressure tests, the annular BOPs shall be tested against the smallest OD drill pipe to be used in the hole section.
§250.737(d)(8)	You must...: (8) Pressure test affected BOP components following the disconnection or repair of any well-pressure containment seal in the wellhead or BOP stack assembly.		Accept proposed text

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.737(d)(9)	You must...: (9) Function test annular and pipe/variable bore ram BOPs every 7 days between pressure tests.	Complies with API 53, surface and subsea.	You must...: (9) Function test annular and pipe/variable bore ram BOPs every 7 days or as operations allow. Pressure tests qualify as function tests.
§250.737(d)(10)	You must...: (10) Function test blind-shear ram BOPs every 14 days.	API 53 requires BSR & CSR function testing every 21 days. WCR require function testing the BSR every 14 days. (Both are at the pressure testing interval however, WCR only addresses the BSR and not the CSR.	You must...: (10) Function test blind-shear ram BOPs not to exceed every 21 days.
§250.737(d)(11)	You must...: (11) Actuate safety valves assembled with proper casing connections before running casing.		Accept proposed text
§250.737(d)(12)	You must...: (12) Test and verify closure capability of all ROV intervention functions on your subsea BOP. Additional requirements... (i) Each ROV must be fully compatible with the BOP stack ROV intervention panels. (ii) You must submit test procedures, including how you will test each ROV intervention function, with your APD or APM for District Manager approval. (iii) You must document all your test results and make them available to BSEE upon request.	(12) This is a repeat requirement and may add to some confusion on its intent. (See above) (i) The issue is the stabs and receptacle interfaces but not specifically toward the ROV being FULLY COMPATIBLE. Confusing requirement. Conflicts with API 53.	You must...: (12) test and verify closure of the following critical ROV intervention functions: (1) shear ram close, (2) one pipe ram close, and (3) ram locks and (4) LMRP unlock/unlatch intervention functions on your subsea BOP stack during the pre-deployment (stump) test. Additional requirements... (i) ROV tooling must be compatible with the BOP stack ROV intervention receptacles. (ii) You must submit test procedures, including how you will test each ROV intervention function, with your APD or APM for District Manager approval. (iii) You must document all your test results and make them available to BSEE upon request.
§250.737(d)(13)	You must...: (13) Function test autoshear, deadman, and EDS systems separately on your subsea BOP stack during the stump test. The District Manager may require additional testing of the emergency systems. You must also test the deadman system and verify closure of the shearing rams during the initial test on the seafloor.		You must...: (13) Function test autoshear, deadman, and EDS systems separately on your subsea BOP stack during the stump test. The District Manager may require additional testing of the emergency systems. You must also test the deadman system during commissioning or within 5 years of previous test.
§250.737(d)(13)(i)	Additional requirements... (i) You must submit test procedures with your APD or APM for District Manager approval. The procedures for these function tests must include the schematics of the actual controls and circuitry of the system that will be used during an actual autoshear or deadman event.		Accept proposed text
§250.737(d)(13)(ii)	(ii) The procedures must also include the actions and sequence of events that take place on the approved schematics of the BOP control system and describe specifically how the ROV will be utilized during this operation.		Accept proposed text

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.737(d)(13) (iii)	(iii) When you conduct the initial deadman system test on the seafloor, you must ensure the well is secure and, if hydrocarbons have been present, appropriate barriers are in place to isolate hydrocarbons from the wellhead. You must also have an ROV on bottom during the test.		(iii) When you conduct the initial deadman system test during commissioning or within 5 years of the previous test on the seafloor, you must ensure the well is secure and, if hydrocarbons have been present, appropriate barriers are in place to isolate hydrocarbons from the wellhead. You must also have an ROV on bottom during the test.
§250.737(d)(13) (iv)	(iv) The testing of the deadman system on the seafloor must indicate the discharge pressure of the subsea accumulator system throughout the test.		Accept proposed text
§250.737(d)(13) (v)	(v) For the function test of the deadman system during the initial test on the seafloor, you must have the ability to quickly disconnect the LMRP should the rig experience a loss of station-keeping event. You must include your quick-disconnect procedures with your deadman test procedures.	Conflicts w/ API 53, does not require a DMAS test on initial landing but does require a drawdown test specific to the DMAS system accumulators.	(v) For the function test of the deadman system during commissioning or within 5 years of the previous test on the seafloor, you must have the ability to quickly disconnect the LMRP should the rig experience a loss of station-keeping event. You must include your quick-disconnect procedures with your deadman test procedures.
§250.737(d)(13) (vi)	(vi) You must pressure test the blind-shear ram(s) according to (b) and (c) of this section.		
§250.737(d)(13) (vii)	(vii) If a casing shear ram is installed, you must describe how you will verify closure of the ram.		
§250.737(d)(13) (viii)	(viii) You must document all your test results and make them available to BSEE upon request.		Accept proposed text
§250.737(e)	(e) Prior to conducting any shear ram tests in which you will shear pipe, you must notify the BSEE District Manager at least 72 hours in advance, to ensure that a representative of BSEE will have access to the location to witness any testing.		Accept proposed text
§250.738	The table in this section describes actions that you must take when certain situations occur with BOP systems.		
§250.738(a)	If you encounter the following situation: (a) BOP equipment does not hold the required pressure during a test; Then you must . . . Correct the problem and retest the affected equipment. You must report any problems or irregularities, including any leaks, to the District Manager and on the daily report as required in § 250.746.	All issues encountered while pressure testing, which can be corrected, are noted in the pressure testing report. Any issues that cannot be rectified, but do not impair safe operation (BOP stack still meets industry standards and federal regulations), will be sent to the District office with a statement-of-fact.	If you encounter the following situation: (a) BOP equipment does not hold the required pressure during a test; Then you must . . . Correct the problem and retest the affected equipment. You must report any unrepairable problems or irregularities, including any leaks, to the District office and on the daily report as required in § 250.746.

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.738(b)(1-3)	<p>250.738(b) If you encounter the following situation: (b) Need to repair, replace, or reconfigure a surface or subsea BOP system; Then you must . . . (1) First place the well in a safe, controlled condition as approved by the District Manager (e.g., before drilling out a casing shoe or after setting a cement plug, bridge plug, or a packer).</p> <p>(2) Any repair or replacement parts must be manufactured under a quality assurance program and must meet or exceed the performance of the original part produced by the OEM. (3) You must receive approval from the District Manager prior to resuming operations with the new, repaired, or reconfigured BOP. You must submit a report from a BSEE-approved verification organization to the District Manager certifying that the BOP is fit for service.</p>	Change term "BOP system" to "BOP stack"	<p>If you encounter the following situation: (b) Need to repair, replace, or reconfigure a surface or subsea BOP stack; Then you must . . . (1) First place the well in a safe, controlled condition as approved by the District Manager (e.g., before drilling out a casing shoe or after setting a cement plug, bridge plug, or a packer).</p> <p>(2) Any repair or replacement parts must be manufactured under a quality assurance program and must meet or exceed the performance of the original part produced by the OEM. (3) You must receive approval from the District Manager prior to resuming operations with the new, repaired, or reconfigured BOP. You must submit a report to the District Manager certifying that the BOP is fit for service.</p>
§250.738(c)	<p>If you encounter the following situation: (c) Need to postpone a BOP test due to well-control problems such as lost circulation, formation fluid influx, or stuck pipe; Then you must . . . Record the reason for postponing the test in the daily report and conduct the required BOP test on the first trip out of the hole.</p>		Accept proposed text
§250.738(d)	<p>If you encounter the following situation: (d) BOP control station or pod that does not function properly; Then you must . . .Suspend operations until that station or pod is operable. You must report any problems or irregularities, including any leaks, to the District Manager.</p>		Accept proposed text
§250.738(e)	<p>If you encounter the following situation: (e) Plan to operate with a tapered string; Then you must . . . Install two or more sets of conventional or variable-bore pipe rams in the BOP stack to provide for the following: two sets of rams must be capable of sealing around the larger-size drill string and two sets of pipe rams must be capable of sealing around the smaller size pipe, excluding the bottom hole assembly that includes heavy weight pipe or collars and bottom-hole tools.</p>	We do not see the need for a redundant ram on the smaller size pipe providing this pipe is not across the bop stack while drilling. The annular provides a redundant means to seal against the smaller pipe.	<p>If you encounter the following situation: (e) Plan to operate with a tapered string; Then you must . . . Install two or more sets of conventional or variable-bore pipe rams in the BOP stack to provide for the following: two sets of rams must be capable of sealing around the larger-size drill string and two sets of pipe rams must be capable of sealing around the smaller size pipe in the event that this pipe is across the BOP stack when drilling, and excluding the bottom hole assembly that includes heavy weight pipe or collars and bottom-hole tools.</p>

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
\$250.738(f)	If you encounter the following situation: (f) Plan to install casing rams or casing shear rams in a surface BOP stack; Then you must... Test the ram bonnets before running casing to the rated working pressure or MASP plus 500 psi. The BOP must also provide for sealing the well after casing is sheared. If this installation was not included in your approved permit, and changes the BOP configuration approved in the APD or APM, you must notify and receive approval from the District Manager.	Conflicts with API 53. a) implies that casing has to be sheared (not just drillpipe as previously stated); b) nowhere in the WCR and API 53 is there a requirement to shear casing previously mentioned in either document.	If you encounter the following situation: (f) Plan to install casing rams or casing shear rams in a surface BOP stack; Then you must... Test the ram bonnets seals before running casing to the rated working pressure or MASP/MAWHP plus 500 psi. If this installation was not included in your approved permit, and changes the BOP configuration approved in the APD or APM, you must notify and receive approval from the District Manager.
\$250.738(g)	If you encounter the following situation: (g) Plan to use an annular BOP with a rated working pressure less than the anticipated surface pressure; Then you must . . . Demonstrate that your well-control procedures or the anticipated well conditions will not place demands above its rated working pressure and obtain approval from the District Manager.		Accept proposed text
\$250.738(h)	If you encounter the following situation: (h) Plan to use a subsea BOP system in an ice-scour area; Then you must . . . Install the BOP stack in a well cellar. The well cellar must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.		Accept proposed text
\$250.738(i)	If you encounter the following situation: (i) You activate any shear ram and pipe or casing is sheared; Then you must . . . Retrieve, physically inspect, and conduct a full pressure test of the BOP stack after the situation is fully controlled. You must submit to the District Manager a report from a BSEE-approved verification organization certifying that the BOP is fit to return to service.		If you encounter the following situation: (i) You activate any shear ram and pipe or casing is sheared; Then you must . . . Retrieve, physically inspect, and conduct a full pressure test of the BOP stack after the situation is fully controlled. You must submit to the District Manager a report certifying that the BOP is fit to return to service.
\$250.738(j)	If you encounter the following situation: (j) Need to remove the BOP stack; Then you must . . . Have a minimum of two barriers in place prior to BOP removal. You must obtain approval from the District Manager of the two barriers prior to removal and the District Manager may require additional barriers.		
\$250.738(k)	If you encounter the following situation: (k) In the event of a deadman or autoshear activation, if there is a possibility of the blind-shear ram opening immediately upon re-establishing power to the BOP stack; Then you must . . . Place the blind-shear ram opening function in the block position prior to re-establishing power to the stack. Contact the District Manager and receive approval of procedures for re-establishing power and functions prior to latching up the BOP stack or re-establishing power to the stack.	Language is too prescriptive. Field procedures should address the system.	If you encounter the following situation: (k) In the event of a deadman or autoshear activation, if there is a possibility of the blind-shear ram opening immediately upon re-establishing power to the BOP stack; Then you must address that possibility prior to re-establishing power to the stack. Contact the District Manager and receive approval of procedures for re-establishing power and functions prior to latching up the BOP stack or re-establishing power to the stack.

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.738(l)	250.738(l) If you encounter the following situation: (l) If a test ram is to be used, then you must . . . conduct the test using a test ram that meets the following criteria: (1) The test ram must be connected to the wellhead/BOP connection to the maximum pressure for the approved ram test for the well. All hydraulically operated BOP components must also be functioned during the well connection test.	Exclude hydraulic connectors, wet-mate connectors, and all stubs.	If you encounter the following situation: (l) If a test ram is to be used, then you must . . . conduct the test using a test ram that meets the following criteria: (1) The test ram must be connected to the wellhead/BOP connection to the maximum pressure for the approved ram test for the well. All hydraulically operated well control BOP components must also be functioned during the well connection test.
§250.738(m)	If you encounter the following situation: (m) Plan to utilize any other well-control equipment (e.g., but not limited to, subsea isolation device, subsea accumulator module, or gas handler) that is in addition to the equipment required in this subpart; Then you must . . . Contact the District Manager and request approval in your APD or APM. Your request must include a report from a BSEE-approved verification organization on the equipment's design and suitability for its intended use as well as any other information required by the District Manager. The District Manager may impose any conditions regarding the equipment's capabilities, operation, and testing.		If you encounter the following situation: (m) Plan to utilize any other well-control equipment (e.g., but not limited to, subsea isolation device, subsea accumulator module, or gas handler) that is in addition to the equipment required in this subpart; Then you must . . . Contact the District Manager and request approval in your APD or APM. Your request must include a report on the equipment's design and suitability for its intended use as well as any other information required by the District Manager. The District Manager may impose any conditions regarding the equipment's capabilities, operation, and testing.
§250.738(n)	If you encounter the following situation: (n) You have pipe/variable bore rams that have no current utility or well-control purposes; Then you must . . . indicate in your APD or APM which pipe/variable bore rams meet these criteria and clearly label them on all BOP control panels. You do not need to function test or pressure test pipe/variable bore rams having no current utility, and that will not be used for well-control purposes, until such time as they are intended to be used during operations.		

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.738(c)	If you encounter the following situation: (c) You install redundant components for well-control in your BOP system that are in addition to the required components of this subpart (e.g., pipe/variable bore rams, shear rams, annular preventers, gas bleed lines, and choke/kill side outlets or lines). Then you must . . . Comply with all testing, maintenance, and inspection requirements in this subpart that are applicable to those well-control components. If any redundant component fails a test, you must submit a report from a BSEE-approved verification organization that describes the failure, and confirms that there is no impact on the BOP that will make it unfit for well-control purposes. You must submit this report to the District Manager and receive approval before resuming operations. The District Manager may require additional information.		If you encounter the following situation: (c) You install redundant components for well-control in your BOP system that are in addition to the required components of this subpart (e.g., pipe/variable bore rams, shear rams, annular preventers, gas bleed lines, and choke/kill side outlets or lines); Then you must . . . Comply with all testing, maintenance, and inspection requirements in this subpart that are applicable to those well-control components. If any redundant component fails a test, you must submit a report that describes the failure, and confirms that there is no impact on the BOP that will make it unfit for well-control purposes. You must submit this report to the District Manager and receive approval before resuming operations. The District Manager may require additional information.
§250.738(p)	If you encounter the following situation: (p) Need to position the bottom hole assembly, including heavy-weight pipe or collars, and bottom-hole tools across the BOP for tripping or any other operations. Then you must . . . Ensure that the well has been stable for a minimum of 30 minutes prior to positioning the bottom hole assembly across the BOP. You must have, as part of your well-control plan required by § 250.710, procedures that enable the immediate removal of the bottom hole assembly from across the BOP in the event of a well-control or emergency situation (for dynamically positioned rigs, your plan must also include steps for when the EDS must be activated) before MASP conditions are reached as defined for the operation.	Removed 30 minute stable time period (this time needs to be determined by the operator and based upon offset well data) and removed "immediate" removal as it is not possible to "Immediately" do anything. Actions should be taken as quickly as they can be done while honoring personnel safety risks.	If you encounter the following situation: (p) Need to position the bottom hole assembly, including heavy-weight pipe or collars, and bottom-hole tools across the BOP for tripping or any other operations. Then you must . . . Ensure that the well has been stable prior to positioning the bottom hole assembly across the BOP. You must have, as part of your well-control plan required by § 250.710, procedures that enable the removal of the bottom hole assembly from across the BOP in the event of a well-control or emergency situation (for dynamically positioned rigs, your plan must also include steps for when the EDS must be activated) before MASP/MAWHP conditions are reached as defined for the operation.
§250.739(a)	(a) You must maintain and inspect your BOP system to ensure that the equipment functions as designed. The BOP maintenance and inspections must meet or exceed any OEM recommendations, recognized engineering practices, and industry standards incorporated by reference into the regulations of this subpart, including API Standard 53 (incorporated by reference in § 250.198). You must document how you met or exceeded the provisions of API Standard 53, maintain complete records to ensure the traceability of all critical components beginning at fabrication, and record the results of your BOP inspections and maintenance actions. You must make all records available to BSEE upon request.	Need to clarify the term "critical components." The statement "Engineering practices and industry standards" is too vague and open to inconsistent interpretation. Preventative and remedial maintenance is critical to maintaining a satisfactory level of reliability during the operational life of critical equipment. Risk/condition based maintenance could be improved if we reduced the amount of testing we do as this activity is the most common use, and therefore wear, of the equipment; we know that we are as good as our last test but we want to be confident for our next one.	(a) You must maintain and inspect your BOP system, as defined in API 53 1.1.2 (incorporated by reference in § 250.198), to ensure that the equipment functions as designed. All BOP maintenance and inspections must meet the equipment owner's PM program. You must document how you met or exceeded the provisions of API Standard 53, maintain complete records to ensure the required traceability of the equipment and record the results of your inspections and maintenance actions. You must make all records available to BSEE upon request.

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.739(b)	<p>(b) A complete breakdown and detailed physical inspection of the BOP and every associated system and component must be performed every 5 years. This complete breakdown and inspection may not be performed in phased intervals. A BSEE-approved verification organization is required to be present during the inspection and must compile a detailed report documenting the inspection, including descriptions of any problems and how they were corrected. You must make this report available to BSEE upon request.</p>	<p>The prohibition of phased inspections would put rigs out of service for estimated 6 months minimum. A complete disassembly of a BOP stack introduces major safety risks as well as infant mortality of equipment into system. A requirement to follow this would put our current strategies multiple steps backwards.</p> <p>It is not in line with API 53 (or any other industry standard).</p> <p>There are safety issues with the multiple very heavy lifts in congested areas.</p> <p>Technology exists that allows for detailed inspection without disassembly.</p> <p>There is insufficient data to support any benefits of this approach.</p> <p>There is insufficient infrastructure in the industry to manage this requirement.</p> <p>Continuous survey is a proven method for this and other industries.</p> <p>A single inspection does not make the system any safer.</p> <p>This could affect international rigs coming into the jurisdiction or existing equipment.</p> <p>How does this affect existing equipment?</p> <p>We believe that third party presence is not always required due to the proposed competency requirements that require the subsea teams to be qualified to meet OEM standards.</p> <p>We believe that review of our reports would be sufficient. Any failures or issues discovered during the inspection are reported as part of the Equipment Failure Data Reporting. This will be detrimental to all operators.</p>	<p>(b) At least every five (5) years, the well control system components shall be inspected for repair or remanufacturing in accordance with the equipment owner's PM program and manufacturer's guidelines. Individual components may be inspected on a staggered schedule.</p> <p>As an alternative to a schedule-based inspection program, a rig-specific inspection frequency can vary from this 5 year interval if the equipment owner collects and analyzes condition based data (including performance data) to justify a different frequency. This alternative may include dynamic vs. static seals, corrosion resistant alloy inlays in sealing surfaces, resilient vs. metal to metal seals, replaceable wear plates, etc.</p> <p>For schedule and condition based inspection programs, certain equipment shall undergo a critical inspection (internal/external visual, dimensional, NDE, etc.) annually, or upon recovery if exceeding 1 year: e.g. shear blades, bonnet bolts (or other bonnet/door locking devices), ram shaft button/foot, welded hubs, ram cavities and ram blocks. The actual dimensions shall be verified against the manufacturer's allowable tolerances. Inspections shall be performed by a competent person(s).</p> <p>Consider replacing elastomeric components and checking surface finishes for wear and corrosion during these inspections.</p> <p>Documentation of all repairs and remanufacturing shall be maintained in accordance with API 53 7.6.10.</p> <p>These inspections shall be documented and made available to BSEE District Manager upon request.</p>
§250.739(c)	<p>(c) You must visually inspect your surface BOP system on a daily basis. You must visually inspect your subsea BOP system, marine riser, and wellhead at least once every 3 days if weather and sea conditions permit. You may use cameras to inspect subsea equipment.</p>		<p>Accept proposed text</p>

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.739(d)	(d) You must ensure that all personnel maintaining, inspecting, or repairing BOPs, or critical components of the BOP system, meet the qualification and training criteria specified by the OEMs and recognized engineering practices.	OEMs do not provide training requirements. Training and competency requirements addressed thru SEMS. Recognized engineering practices are addressed thru the applicable API standards and specifications.	(d) Require that the personnel, who maintain, inspect, or repair BOPs or other critical components meet the qualifications and training criteria specified by the equipment owner and that such maintenance, inspection, and repair be undertaken in accordance with API 53.
§250.739(e)	(e) You must make all records available to BSEE upon request. You must ensure that the rig owner maintains your BOP maintenance, inspection, and repair records on the rig for 2 years from the date the records are created or for a longer period if directed by BSEE. You must maintain all design, maintenance, inspection, and repair records at an onshore location for the service life of the equipment.	The equipment design data is proprietary to the OEM and therefore the design cannot be maintained by anybody other than the product design owner.	(e) You must make all records available to BSEE upon request. You must ensure that the equipment owner maintains the BOP maintenance, inspection, and repair records on the rig for 2 years from the date the records are created or for a longer period if directed by BSEE. The equipment owner must maintain all maintenance, inspection, and repair records at an onshore location for the service life of the equipment.
§250.740	You must keep a daily report consisting of complete, legible, and accurate records for each well. You must keep records onsite while well operations continue. After completion of operations, you must keep all operation and other well records for the time periods shown in § 250.741 at a location of your choice, except as required in § 250.746. The records must contain complete information on all of the following:	Is additional Real Time Monitoring required. Real Time Monitoring is not typically done on HWO or other Thru Tree interventions. The cost assessment is unrealistic as the reports are generated by the technical staff in the RTC and not administrative staff. Daily Reports and Event Reports are generated by the technical staff and part of the \$40,000 daily cost.	
§250.740 (a)	(a) Well operations, all testing conducted, and any real-time monitoring data;	These measurements and calculations are done on the rig, regardless if real time is present or not. Onshore monitor will have to have realtime communications with MODU operations, as Crane activity can make S+ bbl swings in Active or Trip tank readings. This can result in erroneous assumptions and invalid conclusions, due to lack of situation awareness.	(a) Well operations, all testing conducted, and real-time monitoring data, per your Monitoring Plan; (b) Descriptions of formations penetrated; (c) Content and character of oil, gas, water, and other mineral deposits in each formation; (d) Kind, weight, size, grade, and setting depth of casing; (e) All well logs and surveys run in the wellbore; (f) Any significant malfunction or problem; and (g) All other information required by the District Manager.
§250.740(b)	(b) Descriptions of formations penetrated;		
§250.740(c)	(c) Content and character of oil, gas, water, and other mineral deposits in each formation;		
§250.740(d)	(d) Kind, weight, size, grade, and setting depth of casing;		Accept proposed text

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.740(e)	(e) All well logs and surveys run in the wellbore;		
§250.740(f)	(f) Any significant malfunction or problem; and	Unclear requirements, covered by 250.740(g)	
§250.740(g)	(g) All other information required by the District Manager.	Additional information required is unknown.	(g) All other information required by the District Manager in the interests of resource evaluation, waste prevention, conservation of natural resources, and the protection of correlative rights, safety, and environment.
§250.741	You must keep records for the time periods shown in the following table.		Accept proposed text
§250.741(a)	You must keep records relating to . . . (a) Drilling; Until . . . 90 days after you complete operations.		Accept proposed text
§250.741(b)	You must keep records for the time periods: (b) Casing and liner pressure tests, diverter tests, BOP tests, and real-time monitoring data; Until . . . 2 years after the completion of operations.	This is not necessary on a decommissioning operation after the well has been plugged. Data set may need to be kept for longer durations in the event of a redrill or sidetrack.	
§250.741(c)	You must keep records relating to . . . (c) Completion of a well or of any workover activity that materially alters the completion configuration or affects a hydrocarbon-bearing zone. Until . . . You permanently plug and abandon the well or until you assign the lease and forward the records to the assignee.		Accept proposed text
§250.742	You must submit to BSEE copies of logs or charts of electrical, radioactive, sonic, and other well logging operations; directional and vertical well surveys; velocity profiles and surveys; and analysis of cores. Each Region will provide specific instructions for submitting well logs and surveys.		
§250.743(a)	(a) For operations in the BSEE GOM OCS Region, you must submit Form BSEE-0133, Well Activity Report (WAR), to the District Manager on a weekly basis. The reporting week is defined as beginning on Sunday (12:00 a.m.) and ending on the following Saturday (11:59 p.m.). This reporting week corresponds to a week (Sunday through Saturday) on a standard calendar. Report any well operations that extend past the end of this weekly reporting period on the next weekly report. The reporting period for the weekly report is never longer than 7 days, but could be less than 7 days for the first reporting period and the last reporting period for a particular well operation. Submit each WAR and accompanying Form BSEE-0133S, Open Hole Data Report, to the BSEE GOM OCS Region no later than close of business on the Friday immediately after the closure of the reporting week. The District Manager may require more frequent submittal of the WAR on a case-by-case basis.		Accept proposed text
§250.743(b)	(b) For operations in the Pacific or Alaska OCS Regions, you must submit Form BSEE-0133, WAR, to the District Manager on a daily basis.		Accept proposed text

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.743(C)	<p>(c) The WAR must include such information as a description of the operations conducted, any abnormal or significant events that affect the permitted operation each day within the report from the time you begin operations to the time you cease operations; any verbal approval received, the well's sit-built drawings, casing, fluid weights, shoe tests, test pressures at surface conditions, and any other information required by the District Manager. For casing cementing operations, indicate type of returns (i.e., full, partial, or none). If partial or no returns are observed, you must indicate how you determined the top of cement. For each report, indicate the operation status for the well at the end of the reporting period. On the final WAR, indicate the status of the well (completed, temporarily abandoned, permanently abandoned, or drilling suspended) and the date you finished such operations.</p>		Accept proposed text
§250.743(C)	<p>(c) The WAR must include such information as a description of the operations conducted, any abnormal or significant events that affect the permitted operation each day within the report from the time you begin operations to the time you cease operations; any verbal approval received, the well's sit-built drawings, casing, fluid weights, shoe tests, test pressures at surface conditions, and any other information required by the District Manager. For casing cementing operations, indicate type of returns (i.e., full, partial, or none). If partial or no returns are observed, you must indicate how you determined the top of cement. For each report, indicate the operation status for the well at the end of the reporting period. On the final WAR, indicate the status of the well (completed, temporarily abandoned, permanently abandoned, or drilling suspended) and the date you finished such operations.</p>		Accept proposed text

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.744(a)	(a) Within 30 days after completing operations, except routine operations as defined in § 250.601, you must submit Form BSEE-0125, End of Operations Report (EOR), to the District Manager. The EOR must include a listing, with top and bottom depths, of all hydrocarbon zones and other zones of porosity encountered with any cored intervals; details on any drill-stem and formation tests conducted; documentation of successful negative pressure testing on wells that use a subsea BOP stack or wells with mudline suspension systems; and an updated schematic of the full wellbore configuration. The schematic must be clearly labeled and show all applicable top and bottom depths, locations and sizes of all casings, cut casing or stubs, casing perforations, casing rupture discs (indicate if burst or collapse and rating), cemented intervals, cement plugs, mechanical plugs, perforated zones, completion equipment, production and isolation packers, alternate completions, tubing, landing nipples, subsurface safety devices, and any other information required by the District Manager. The EOR must indicate the status of the well (completed, temporarily abandoned, permanently abandoned, or drilling suspended) and the date of the well status designation. The well's status date is subject to the following:		Accept proposed text
§250.744(a)(1)	(1) For surface well operations and riserless subsea operations, the operations end date is subject to the discretion of the District Manager; and		Accept proposed text
§250.744(a)(2)	(2) For subsea well operations, the operation end date is considered to be the date the BOP is disconnected from the wellhead unless otherwise specified by the District Manager.		Accept proposed text
§250.744(b)	(b) You must submit public information copies of Form BSEE-0125 according to § 250.186(b).		Accept proposed text
§250.745	The District Manager or Regional Supervisor may require you to submit copies of any or all of the following well records:		
§250.745(a)	(a) Well records as specified in § 250.740;		
§250.745(b)	(b) Paleontological interpretations or reports identifying microscopic fossils by depth and/or washed samples of drill cuttings that you normally maintain for paleontological determinations. The Regional Supervisor may issue a Notice to Lessees that sets forth the manner, timeframe, and format for submitting this information;		
§250.745(c)	(c) Service company reports on cementing, perforating, acidizing, testing, or other similar services; or		
§250.745(d)	(d) Other reports and records of operations.		

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
\$250.746	You must record the time, date, and results of all casing and liner pressure tests. You must also record pressure tests, actuations, and inspections of the BOP system, system components, and annular seals in the daily report described in § 250.746. In addition, you must:	If you encounter the following situation: (a) BOP equipment does not hold the required pressure during a test; (b) leaks occur; (c) problems are noted that the affected equipment may have any unreparable problems or irregularities, including any leaks, to the District office and on the daily report as required in 250.746	
\$250.746(a)	(a) Record test pressures on pressure charts;		
\$250.746(b)	(b) Require your onsite lessee representative, designated rig or contractor representative, and pump operator to sign and date the pressure charts and daily reports as correct;		
\$250.746(c)	(c) Document on the daily report the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. For subsea BOP systems, you must also record the closing times for annular and ram BOPs. You may reference a BOP test plan if it is available at the facility;		
\$250.746(d)	(d) Identify on the daily report the control station and pod used during the test (identifying the pod does not apply to coiled tubing and snubbing units);		
\$250.746(e)	(e) Identify on the daily report any problems or irregularities observed during BOP-system testing and record actions taken to solve the problems or irregularities. Any leaks associated with the BOP system during testing, including any detected problems or irregularities, and must be reported immediately to the District Manager, and documented in the WAR. If any problems or irregularities are observed during testing, operations must be suspended until the District Manager determines that you may continue; and	Suspending operations may not be safe; we need to be able to handle minor issues internally.	
\$250.746(f)	(f) Retain all records, including pressure charts, daily reports, and referenced documents pertaining to tests, actuations, and inspections at the facility for the duration of the operation. After completion of the operation, you must retain all the records listed in this section for a period of 2 years at the facility. You must also retain the records at the lessee's field office nearest the facility or at another location available to BSEE. You must make all records available to BSEE upon request.		
\$250.1612	Well-control drills must be conducted for each drilling crew in accordance with the requirements set forth in § 250.711 of this part or as approved by the District manager.		

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§ 250.1703(b)	(b) Permanently plug all wells. All packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198);	Need to clarify the reference to 11D1.	(b) Permanently plug all wells. After the implementation date of this regulation, all permanently installed (as defined in the APD and/or APM) packers and bridge plugs installed during decommissioning must comply with API Spec. 11D1 (as incorporated by reference in § 250.198);
§250.1703(e)	(e) Clear the seafloor of all obstructions created by your lease and pipeline right-of-way operations;		Accept proposed text
§250.1703(f)	(f) Follow all applicable requirements of Subpart G;		Accept proposed text
§250.1704(g)(1)(i-ii)	Decommissioning applications and reports: (g) Form BSEE-0124, Application for Permit to Modify (APM). The submission of your APM must be accompanied by payment of the service fee listed in § 250.125; When to submit: (1) Before you temporarily abandon or permanently plug a well or zone, Instructions: (i) Include information required under §§ 250.1712 and 250.1721. (ii) When using a BOP for abandonment operations, include information required under § 250.731.		Accept proposed text
§250.1704(g)(2)	When to submit: (2) Before you install a subsea protective device, Instructions: Refer to § 250.1722(a).		Accept proposed text
§250.1704(g)(3)	When to submit: (3) Before you remove any casing stub or mud line suspension equipment and any subsea protective device, Instructions: Refer to § 250.1723.		Accept proposed text
§250.1704(h)(1)	(h) Form BSEE-0125, End of Operations Report (EOR); When to submit: (1) Within 30 days after you complete a protective device trawl test, Instructions: include information required under § 250.1722(d).		Accept proposed text
§250.1704(h)(2)	When to submit: (2) Within 30 days after you complete site clearance verification activities, Instructions: Include information required under § 250.1743(a).		Accept proposed text
§250.1715(a)(3)(iii)(B)	(B) A casing bridge plug set 50 to 100 feet above the top of the perforated interval and at least 50 feet of cement on top of the bridge plug;		

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BSEE Proposed Well Control Rule Cost and Economic Analysis

July 2015

Prepared for:
American Petroleum Institute (API)

Prepared by:



Executive Summary

Introduction

The U.S. DOI Bureau of Safety and Environmental Enforcement (BSEE) recently published new requirements and procedures related to the proposed rule “Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control” (hereafter, proposed rule). Quest Offshore Resources (hereafter, Quest Offshore or Quest) and Blade Energy Partners (hereafter Blade Energy or Blade) undertook a study to evaluate the potential cost and economic impact effects of the proposed rule (and associated sections and subsections) on oil and gas drilling operations in the US Gulf of Mexico (GOM), and the influence that these effects would have on the broader economy. Although the proposed rule would apply to all US offshore oil and natural gas development, only the impacts to the Gulf of Mexico were considered for this study.

This study examines the proposed rule, determines the estimated cost and impact of the rules, and attributes these costs and impacts to a model of project design, economics and timelines to determine the effects these rules could have on overall GOM oil and gas development. Once the impact on GOM activity was projected, estimates of the related spending and employment were calculated to quantify the overall economic impact of the proposed rule.

Cost of the Proposed Rule

Construction of a detailed analysis for each individual section/requirement of the proposed rule was undertaken by Quest Offshore and Blade Energy. The increased costs resulting from the rules adoption are expected to further increase expenses incurred by industry participants throughout the study period. The cost estimates presented in the study exclude many costs already being spent by the industry prior to the publishing of the proposed rule.

The increased costs associated with the proposed rule are likely to be felt throughout the offshore oil and gas supply chain. Certain operators and contractors, however, are likely to be effected more than others. Cumulative direct costs due to the adoption of the proposed rule as currently written are estimated at over \$32 billion for the ten years from 2017 to 2026. The expected impact of the proposed rule will be an increase in the total time and cost required to drill many offshore wells, as well as lead to the replacement of blow out preventers (BOP) and other capital equipment. (Table 1)

Table 1: 10 Year Direct Cost Estimates – Base Development Scenario (\$Millions¹)

Category	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
BOP Replacement or Modification	\$925	\$926	\$1,336	\$1,331	\$1,373	\$1,465	\$1,419	\$978	\$1,041	\$1,052	\$11,846
Compliance and Documentation	\$11	\$12	\$11	\$12	\$13	\$13	\$14	\$13	\$12	\$15	\$127
Containment	\$113	\$114	\$179	\$181	\$190	\$99	\$97	\$98	\$85	\$86	\$1,241
Rig Requirements	\$204	\$205	\$205	\$215	\$239	\$239	\$240	\$244	\$247	\$250	\$2,289
Real Time Monitoring (RTM)	\$74	\$72	\$73	\$85	\$83	\$52	\$56	\$83	\$63	\$50	\$670
Tubing and Wellhead Equipment ²	\$33	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$38
Well Design	\$1,062	\$1,470	\$1,597	\$1,721	\$1,691	\$1,739	\$1,551	\$1,357	\$1,601	\$1,830	\$15,620
Grand Total	\$2,421	\$2,800	\$3,402	\$3,547	\$3,589	\$3,606	\$3,378	\$2,753	\$3,050	\$3,284	\$31,831

Source: Quest Offshore Resources, Inc.

Impact of Proposed Rule – Gulf of Mexico Oil and Gas Development

If the proposed rule is implemented as written, it would likely reduce the total amount of Gulf of Mexico oil and natural gas activity, including the number of wells drilled and projects developed. The proposed rule will likely negatively influence deepwater development the most, especially high pressure, high temperature, and ultra-deep water wells which may no longer be drillable, and the resources that these wells might have developed may be lost. A significant number of both shallow and deep water wells drilled into depleted reservoirs may also become undrillable, and those resources would also remain undeveloped. These lost reserves would primarily result from the effects of §250.414, "Planned safe drilling margins", though other new regulations may also have a significant effect on the ability to produce from these reserves. Adoption of the proposed rules is expected to lead to a decrease of an average of around 20 exploration wells drilled per year and around 29 development wells per year. Some of these wells are expected to begin drilling, only to be abandoned prior to completion due to the proposed rule.

This study projects that oil and natural gas production in the Gulf of Mexico will be 2.28 million barrels of oil equivalent (BOE) per day in 2017, and grow to 3.10 million BOE per day by 2030. Under the proposed rule, Gulf of Mexico production is forecasted to be nearly 15% or 0.48 million BOE per day lower by 2030.

Total cumulative spending on offshore oil and natural gas development in the Gulf of Mexico OCS is projected at nearly \$550 billion between 2017 and 2030 or roughly \$39.2 billion per year. If the proposed rule is adopted, cumulative spending is projected at \$493 billion; an average reduction of about \$4 billion or over 10 percent per year.

Economic Impact of Proposed Rule

The study projects total employment supported from the Gulf of Mexico offshore oil and natural gas industry to rise from approximately 363 thousand in 2015 to over 466 thousand by 2030 under the base development scenario. The adoption of the proposed rule is expected to lead to a reduction in

¹ All costs, spending, GDP impacts, and government revenues are calculated in constant 2014 dollars.

² Tubing and Wellhead Equipment costs associated with Well Design requirements in the proposed rule are included in Well Design Costs (Ex. increased casing costs due to drilling margin requirements.)

industry supported employment levels by over 50,000 by as early as 2027 due to reduced oil and natural gas development. (Table 2)

Table 2: Estimated Total Supported Employment Levels by Scenario – 2010 to 2030 (Thousands)

Case	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case	409	409	408	412	421	363	400	419	441	449	449
Proposed Rule	409	409	408	412	421	363	400	412	417	423	413
Difference	-	-	-	-	-	-	-	7	24	26	36

Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Case	434	433	430	434	438	461	469	467	460	467
Proposed Rule	398	399	387	388	403	415	418	411	409	414
Difference	36	34	43	46	35	46	51	56	51	53

Source: Quest Offshore Resources, Inc.

The Gulf of Mexico offshore oil and natural gas industry will contribute an estimated \$31.35 billion annually to US GDP in 2015, and is projected to grow to over \$40 billion by 2030 (Table 3). The proposed rule, if enacted as written, is projected to lead to a reduction of GDP supported Gulf of Mexico oil and natural gas activities of \$4 billion annually by 2030. The 10-year cumulative GDP cost burden of the rule from 2017 to 2026 is estimated at \$28.5 billion.

Table 3: Estimated GOM Supported GDP by Scenario – 2010 to 2030 (\$Millions)

Case	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case	\$34,726	\$35,098	\$35,311	\$34,998	\$35,946	\$31,350	\$34,513	\$36,077	\$38,084	\$38,862	\$38,699
Proposed Rule	\$34,726	\$35,098	\$35,311	\$34,998	\$35,946	\$31,350	\$34,513	\$34,726	\$36,937	\$37,817	\$36,857
Difference	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$1,351)	(\$1,147)	(\$1,045)	(\$1,841)

Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Case	\$37,332	\$36,991	\$36,661	\$36,948	\$37,330	\$39,618	\$40,400	\$40,297	\$39,641	\$40,141
Proposed Rule	\$35,099	\$34,186	\$33,523	\$33,819	\$34,297	\$35,281	\$35,900	\$36,851	\$35,682	\$36,133
Difference	(\$2,233)	(\$2,805)	(\$3,138)	(\$3,130)	(\$3,034)	(\$4,337)	(\$4,500)	(\$3,445)	(\$3,960)	(\$4,007)

Source: Quest Offshore Resources, Inc.

Annual government revenues from Gulf of Mexico lease sales, rents, and royalties is expected to rise from about \$5 billion in 2015 to \$13 billion by 2030 under the base development scenario. Reduced oil and natural gas development anticipated under the proposed rule is projected to lead to lower overall government revenues, primarily as a result of lower production royalties being collected with lower production volumes. Reduced government revenues could be as high as \$1 billion per year as early as 2023, and \$2 billion by 2028. The 10-year cumulative lost government revenue burden of the rule from 2017 to 2026 is estimated at \$10 billion.

Table 4: Estimated State and Federal Government Revenues from GOM Oil and Natural Gas by Scenario 2010 to 2030 (\$Millions)

Case	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case	\$6,361	\$6,177	\$7,515	\$7,219	\$7,079	\$5,177	\$7,013	\$7,625	\$8,650	\$8,262	\$8,828
Proposed Rule	\$6,361	\$6,177	\$7,515	\$7,219	\$7,079	\$5,177	\$7,013	\$7,389	\$7,533	\$7,746	\$8,110
Difference	\$0	\$0	\$0	\$0	\$0	(\$0)	(\$0)	(\$236)	(\$517)	(\$516)	(\$719)

Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Case	\$9,188	\$9,518	\$9,953	\$10,307	\$10,909	\$11,247	\$11,780	\$12,222	\$12,777	\$13,254
Proposed Rule	\$8,267	\$8,557	\$8,740	\$8,889	\$9,164	\$9,580	\$9,865	\$10,148	\$10,488	\$10,870
Difference	(\$921)	(\$961)	(\$1,213)	(\$1,418)	(\$1,745)	(\$1,667)	(\$1,915)	(\$2,074)	(\$2,289)	(\$2,385)

Source: Quest Offshore Resources, Inc.

Adoption of the proposed "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control" rule is expected to significantly increase costs for operators, contractors, and other participants in the Gulf of Mexico offshore oil and natural gas industry. This will likely lead to reduced activity and spending, which is projected to lower production, employment levels, and the growth in GDP and government revenues.

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Section 1 - Introduction

In the Gulf of Mexico, the oil and gas industry has a tremendous influence on the local economies of the Gulf coast and the broader U.S. economy by providing desirable and well-paying employment for hundreds of thousands of Americans, creating revenues for many levels of the U.S. government, and by contributing to the country's energy needs. The industry has grown into the world leader in offshore production, safety, technology, and scientific research. The shallow and mid-water Gulf production areas have been longstanding sources of employment and production, though those areas have been struggling to overcome the economic barriers of production in those now-mature fields, and production has been declining.

Recently, efforts to revitalize mature fields and a shift towards production and activity in deepwater areas of the region have been renewing the strength of the offshore industry, which is poised to reverse the long-standing trend of decline in offshore production volumes that began in the 1980s. Due to the work being done in the deepwater Gulf of Mexico, the industry's global influence has grown steadily, along with the positive economic benefits which it brings. The Gulf has steadily grown into one of the world's most prominent and important oil and natural gas production areas, both in terms of economic value and importance to the global oil and gas industry.

Through an expanded and rigorous set of industry standards put in place over the last five years, the Gulf of Mexico has come to be seen throughout the world as the standard of safety in deepwater and high pressure/high temperature production. Companies operating in the region have not only developed technologies capable of safely and reliably operating in previously impossible-to-reach areas and depths, but have built the region into a center for research and innovation, and a global leader in safety, reliability and technology. As a result of the importance of the industry to the U.S. economy and energy security, any significant changes to regulations should be carefully evaluated.

1.1 Purpose of the Report

Following the announcement of proposed changes to the blowout preventer systems and well control regulations, "Oil and Gas and Sulphur Operations in the Outer Continental Shelf – Blowout Preventer Systems and Well Control", by the Bureau of Safety and Environmental Enforcement (BSEE), Quest Offshore Resources was commissioned by the American Petroleum Institute (API), in collaboration with Blade Energy Partners, to provide an independent evaluation of the potential costs associated with the proposed rule. In addition, potential impacts on Gulf of Mexico oil and natural gas development, supported employment, GDP, and government revenue were also to be projected.

The report seeks to identify the costs associated with additional engineering, regulatory oversight, constrained drilling margins, additional BOP construction and maintenance requirements, changes to the regulations surrounding casings and decommissionings, real time monitoring and well containment regulations, amongst others. Once these costs are established, the report will determine the effect that these additional cost burdens will have on project viability, the broad health of the U.S. oil and gas industry and the US economy as a whole.

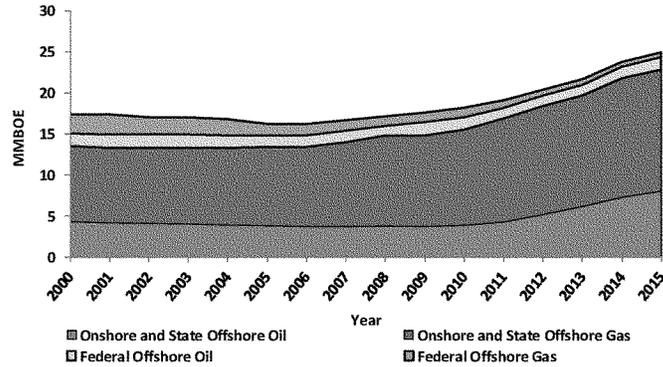
1.2 Report Structure

In this report, Quest will first outline the study methodology in Section 3, followed by a summary of the direct costs associated with the new regulations in Section 4. Following that summary, the study will present forecasts of US offshore oil and gas activity in both the current regulatory environment and under the proposed rule in Section 5. Based on the findings from the activities forecasts, the study then outlines the macroeconomic effects of the proposed regulations on total employment, gross domestic product (GDP) and government revenues in Section 6. Following the findings and conclusions in Section 7, the tables and appendices section contains detailed information on the specific assumptions (Section 8), calculations and findings of the study, as well as a line-by-line analysis of the proposed rule.

1.3 Projected Gulf of Mexico Oil and Natural Gas Development

In recent years, total U.S. oil and natural gas production has increased from approximately 17 million barrels of oil equivalent (MMBOE) in 2006 to over 25 MMBOE in 2015 (Figure 1). This is primarily due to rising production from shale gas and tight oil formations. The dramatic increase in onshore unconventional oil and natural development has been a major contributor in increasing U.S. energy security as well as a significant contributor to the economic recovery in a number of states. U.S. offshore oil and natural gas production, predominately from the Gulf of Mexico, has recently declined. There are, however, a large number of projects under development in the Gulf that are poised to significantly increase output.

Figure 1: U.S. Oil and Natural Gas Production 2000 to 2015



Source: Energy Information Administration

As of April 2015, U.S. domestic crude production has grown to 9.7 MMbbl/d (million barrels of oil per day), distributed through:

- 1.51 MMboe/d from the Gulf of Mexico Federal Outer Continental Shelf

- .046 MMboe/d from offshore California
- .51 MMboe/d from onshore and offshore Federal Alaska
- 7.6 MMboe/d from onshore (including shale) and offshore State waters

Natural gas production nationwide has also grown to 75 BCF/d (billion cubic feet of marketed production per day). It is estimated that the oil and gas industry currently supports 9.8 million jobs nationwide³.

Under the current regulatory structure, growing production from the U.S. offshore areas driven by the Gulf of Mexico OCS is expected both by this study as well as other sources such as the U.S. Energy Information Administration. While this forecast shows a positive outlook for US oil and gas production and energy security, there is the potential for these regulations to impact overall output, and hinder the US return to energy dominance.

1.4 Excluded From This Study

This paper has been limited in scope to the assessment of the effects of the proposed rule, "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control" on the Gulf of Mexico OCS, though the rule will affect all U.S. OCS offshore oil and natural gas exploration and production areas both current and future. The study also does not attempt to calculate the effects of the proposed rule on mid-stream or down-stream oil and natural gas entities. In addition, the calculated government revenue potential does not include personal income taxes, corporate income taxes or local property taxes.

Given the unpredictable nature of advancements in technology and innovation in the oil and gas industry, the scope of this paper was limited to the effects that new regulations would have on future activity with the assumption that the methods and equipment mentioned in the regulation would still be in use at the end of the study period. It is entirely possible that new designs, methods and target reservoirs would change over time and no longer fall under the umbrella of these regulations, but if that were the case, the effects would be primarily felt toward the end of the forecast period.

In addition to the possibility of new technologies being used in the region, the study has also excluded the effects of activity in other regions inclusive of Alaska, Pacific, and Atlantic OCS regions. It is a very likely possibility that exploration and production activities in the OCS areas will see similar disruptions within the future activity forecast under the proposed regulations.

Overall, given the constraints and assumptions discussed above, it is likely that the costs and economic impacts presented in this study represent a conservative projection of the impact of the proposed rule.

³ Source PwC – http://www.apl.org~/media/Files/Policy/Obts/Economic_impacts_Ong_2011.pdf

1.5 About Quest Offshore

Quest Offshore Resources, Inc. is a full-service market research and consulting firm focused on the global offshore oil and natural gas industry. As a function of Quest's core business, the company is engaged daily in the collection and analysis of data as it relates to the offshore oil and natural gas industry. Quest serves the global community of operating oil and natural gas companies, their suppliers, financial firms, and many others by providing detailed data and analysis on capital investment and operational spending undertaken by the offshore industry. Quest collects and develops market data from a variety of sources at the project level for projects throughout the world.

Data is tracked in Quest's proprietary Enhanced Development Database as well as additional proprietary databases related other facets of the global supply chain worldwide. Quest aggregates capital and operating expenditures on a project by project basis for projects worldwide, with detailed information recorded on the supply of the equipment and services necessary to develop individual offshore oil and natural gas projects. Quest Offshore tracks not only existing or historical projects, but also projects that are in all stages of development from the prospect (or undrilled target) stage through to producing and decommissioned projects. For projects without firm development information, Quest utilizes benchmarking based on the proprietary databases mentioned above to forecast development timing and scenarios appropriate to the type of development, the developments' characteristics and region.

1.6 About Blade Energy

Blade Energy Partners is an independent consulting company that focuses on resolving the challenges of complex projects in the energy industry. The company provides leading-edge expertise to solve drilling, completion, production, reservoir and pipeline challenges. Blade works with the sole objective of safely and efficiently maximizing returns on reserves and assets. Since its creation over ten years ago, Blade has collaborated on a wide variety of engineering, research, and development projects in several sectors of the oil and gas and geothermal industries. Blade comprises over 70 engineers, scientists, and project managers. Sixty percent of our staff possess advanced degrees and of those, twenty percent hold doctoral degrees in applied science or engineering. Blade engineers are highly experienced, with, on average, 20+ years in the industry, serving major operating and service companies.

Section 2 - Study Methodology

2.1 Data Development

The authors of this report (Blade Energy and Quest Offshore) have undertaken a detailed engineering and economic analysis of the Bureau of Safety and Environmental Enforcement (BSEE), proposed rule on "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control", as published in the Federal Register Vol. 80 Friday, No. 74 on April 17, 2015 with the purpose of providing a summary of the most impactful areas of these regulations. This study in no way is exhaustive, especially in light of the relatively short period available to develop this analysis and the highly technical nature of these regulations.

This analysis focuses on the likely engineering burdens and operational effects of these regulations and attempts to calculate the cost of overcoming these burdens wherever possible. As such, this analysis is essentially forward looking and potentially subject to significant changes based on the content of the final rule as implemented by BSEE, the way in which it is implemented, and a variety of other factors. However, the report's authors believe that this approach is the best available way to consider this rule, as a backwards looking review based on previous industry activity would likely overstate the effects of these regulations.

Similarly, a more narrow view of the regulations which focuses solely on the narrow cost of implementing individual sections of the proposed rule without taking into account the engineering and operational burdens imposed by the regulations is likely to underestimate the projected costs of their implementation. Due to the limited time available to prepare this report, as well as the significant uncertainties about the way proposed rule would be implemented if enacted, the projected costs, engineering requirements and operational burdens for all proposed regulations are not included in this report. Additionally, the internal costs to BSEE of implementing and administering the proposed rule are not calculated in this report.

2.2 Engineering Review

The engineering review of the proposed rule was undertaken by a number of by various subject matter experts within Blade.. The review focused on the likely engineering and operational effects of these regulations and attempts to calculate the cost of overcoming these burdens wherever possible, while identifying any burdens imposed by the regulation which could not be overcome by additional engineering or operational means. The engineering review attempted to provide the most reasonable outcome and implications of the proposed regulations, while emphasizing the likely effects of the adoption of the regulations as written. Blade provides its independent view expressly disclaiming any warranty, liability, or responsibility for completeness, accuracy, use, or fitness to any person for any reason.

2.3 Limitations of the Report

The report's authors make no representation as to the effects of proposed regulations not addressed specifically in this report and do not discount the possibility that these proposed changes could

impose significant engineering, operational or other burdens on industry or regulators. The report's authors' estimates herein of the effects that BSEE's Proposed Rule will have on current and future engineering, operations and advances in technology are an independent good faith qualitative view arising from considerations by various subject matter experts within Quest Offshore (an independent consulting firm focused on offshore oil and gas operations and economics) and Blade Energy, (an engineering consulting company in well design, engineering and operations). Both Quest Offshore and Blade Energy are providing this independent view expressly disclaiming any warranty, liability, or responsibility for completeness, accuracy, use, or fitness to any person for any reason.

2.4 Cost Calculations

The cost calculations associated with the proposed rule were developed by Quest by calculating the projected engineering and operational burdens by reasonable assumptions of the costs associated with them and the length or scale of these burdens. (ex. \$923 for an engineering man day based on the Society of Professional Engineers salary survey and projections of additional employment costs). All costs associated with the regulation were calculated on the most economic method for overcoming the burden imposed by the regulations and any burdens which would overlap with other burdens imposed by the regulations were discounted to avoid double counting. All costs presented in this study are in constant 2014 dollars.

2.5 Scenario Development

The report's scenario development focused on constructing a tiered "bottom-up" model that separates the complete life cycle of offshore operations and subsequent effects into three main categories and five sub categories. The three main categories are as follows; an "Activity" model that assesses potential reserve information in the context of estimating the possible number of projects within the Gulf of Mexico OCS and the currently forecasted projects and trends in exploration and project development in the region; a "Spending" model based on the requirements to develop projects within the "Activity Forecast"; and an "Economic" model focused on the economic impact on employment and government revenue from the "Spending" model. These categories include, leasing activity, drilling, infrastructure & project development, and production & operation.

After the creation of the baseline model, the operational, cost, drilling and development impacts of the report's analysis of the proposed rule, "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control", were applied to the base scenario forecast resulting in the creation of the "Proposed Rule Scenario" which attempts to provide a reasonable projection of oil and natural gas exploration and development activity in the Gulf of Mexico OCS if the proposed rule was enacted as it is currently proposed. After the development of this scenario, the scenario's potential implications for oil and natural gas production, employment, GDP, and government revenues were then calculated.

Section 3 - Summary of Potential Costs

The proposed rule "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control" is expected to have significant direct costs to entities developing oil and natural gas resources in the US OCS such as the Gulf of Mexico. In addition to direct costs, the proposed rule is likely to impose additional costs to the US economy due to slower or reduced OCS development. While the increased costs of the rule are likely to be felt by all participants in Gulf of Mexico OCS oil and natural gas exploration activities, the effects are most likely to disproportionately affect certain operators and contractors.

The authors of this report (Blade Energy and Quest Offshore) have undertaken a detailed engineering and economic analysis of the proposed rule with the purpose of projecting the total cost of the proposed rule if implemented as currently written. This analysis is in no way is exhaustive, especially in light of the relatively short period available to develop this analysis, and the highly technical nature of these regulations. This analysis focuses on the likely engineering and operational effects of these regulations and wherever possible attempts to calculate the cost of overcoming these burdens.

The following table, prepared by Quest Offshore Resources, presents summary of the estimated direct costs of the proposed rule (Table 5).

Table 5: Estimated 10 Year Costs by Rule by Subsection – 2017 to 2026 (\$Millions)

30 CFR Proposed Regulation Reference	Subsection	10 Year Cumulative Cost (2017 to 2026) Base Development Scenario	Average Annual Cost Base Development Scenario	Line
§ 250.107 (a)	Compliance and Documentation	\$65.2	\$6.5	1
§ 250.107 (e)	Compliance and Documentation	\$61.7	\$6.2	2
§ 250.1703 (b)	Well Design	Contributes to Packers and bridge plugs inventory loss	See line 86	3
§ 250.1703 (f)	Well Design	Not currently calculated ⁴		4
§ 250.413 (d)	Well Design	\$6.9	\$0.69	5
§ 250.414 (c)	Well Design	\$10,689	\$1,069	6
§ 250.414 (j)	Well Design	\$6.9	\$0.69	7
§ 250.414 (k)	Well Design	\$1,126	\$113	8
§ 250.415 (a)	Well Design	\$26	\$2.6	9
§ 250.418 (g)	Well Design	\$3.5	\$0.346	10
§ 250.420 (a)(6)	Well Design	\$1,126	\$113	11
§ 250.420 (b)(4)	Well Design	\$1.7	\$0.173	12
§ 250.420 (c)(2)	Well Design	\$983	\$98	13
§ 250.421 (b)	Well Design	\$441	\$44	14
§ 250.427 (b)	Well Design	Large dead weight loss of wells / projects from forecast	See line 6	15
§ 250.428 (b)	Well Design	\$195	\$19.5	16
§ 250.428 (c)	Well Design	Not currently calculated		17
§ 250.428 (k)	Well Design	\$1.7	\$0.173	18
§ 250.462	Containment	\$1,240	\$124	19
§ 250.462 (b)	Containment	Contributes to containment	See line 19	20
§ 250.462 (c)	Containment	\$1.1	\$0.11	21
§ 250.462 (d)	Well Design	\$195	\$19.5	22
§ 250.462 (e)	Containment	Contributes to containment	See line 19	23
§ 250.518 (New e)	Tubing and wellhead equipment	Contributes to Packers and bridge plugs inventory loss	See line 86	24
§ 250.518 (e)(2)	Tubing and wellhead equipment	\$1.1	\$0.113	25
§ 250.518 (e)(4)	Tubing and wellhead equipment	\$1.7	\$0.173	26
§ 250.518 (New f)	Tubing and wellhead equipment	\$1.7	\$0.173	27
§ 250.619 (f)	Tubing and wellhead equipment	\$1.7	\$0.173	28
§ 250.710	Rig Requirements	\$2,288	\$229	29
§ 250.712	Rig Requirements	Not currently calculated		30
§ 250.712 (a)	Rig Requirements	Not currently calculated		31
§ 250.712 (e)	Rig Requirements	Not currently calculated		32
§ 250.712 (f)	Rig Requirements	Not currently calculated		33
§ 250.720	Well Design	Not currently calculated		34
§ 250.721 (a)	Well Design	Not currently calculated		35
§ 250.721 (e)	Well Design	\$327	\$33	36
§ 250.721 (f)	Well Design	\$12.2	\$1.2	37
§ 250.721 (g)	Well Design	\$478	\$48	38
§ 250.722	Well Design	\$0.346	\$0.03	39
§ 250.723	Well Design	Not currently calculated		40
§ 250.724	RTM	\$670	\$67	41
§ 250.730	BOP	Contributes to BOP replacement	See line 85	42
§ 250.730 (a)(3)	BOP	Not currently calculated		43
§ 250.730 (a)(4)	BOP	Not currently calculated		44

⁴ Sections of the proposed rule marked as not currently calculated denote sections with some expected cost and/or operational burden that was unable to be calculated due to the time limitations associated with this study.

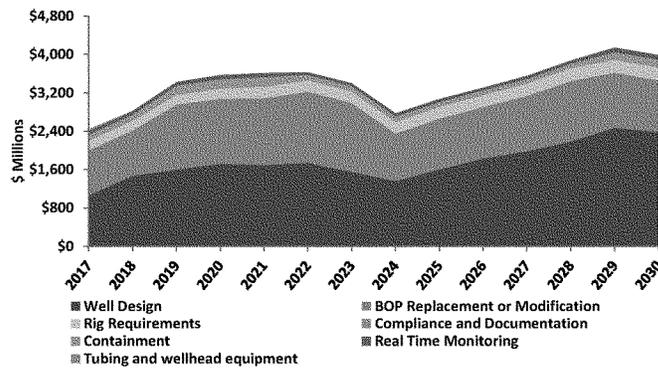
30 CFR Proposed Regulation Reference	Subsection	10 Year Cumulative Cost (2017 to 2026) Base Development Scenario	Average Annual Cost Base Development Scenario	Line
§ 250.730 (d)	BOP	Contributes to BOP replacement	See line 85	45
§ 250.731 (a & b)	BOP	\$3.3	\$0.33	46
§ 250.731 (c)	BOP	BSEE Approved Verification Organization ⁵	See Footnote	47
§ 250.731 (d)	BOP	BSEE Approved Verification Organization	See Footnote 5	48
§ 250.731 (e)	BOP	\$3.3	\$0.331	49
§ 250.731 (f)	BOP	BSEE Approved Verification Organization	See Footnote 5	50
§ 250.732	BOP	\$231	\$23	51
§ 250.732 (a)	BOP	BSEE Approved Verification Organization	See Footnote 5	52
§ 250.732 (b)	BOP	\$45	\$4.5	53
§ 250.732 (c)	BOP	BSEE Approved Verification Organization	See Footnote 5	54
§ 250.732 (d)	BOP	\$1.3	\$0.13	55
§ 250.732 (e)	BOP	BSEE Approved Verification Organization	See Footnote 5	56
§ 250.733	BOP	BSEE Approved Verification Organization	See Footnote 5	57
§ 250.733 (b)	BOP	Not currently calculated		58
§ 250.733 (e)	BOP	\$5.5	\$0.6	59
§ 250.733 (f)	BOP	Not currently calculated		60
§ 250.734	BOP	Contributes to BOP replacement	See line 85	61
§ 250.734 (a)(1)	BOP	Contributes to BOP replacement	See line 85	62
§ 250.734 (a)(3)	BOP	Contributes to BOP replacement	See line 85	63
§ 250.734 (a)(4)	BOP	Contributes to BOP replacement	See line 85	64
§ 250.734 (a)(5)	BOP	Not currently calculated	See line 85	65
§ 250.734 (a)(6)	BOP	Contributes to BOP replacement	See line 85	66
§ 250.734 (a)(15)	BOP	Contributes to BOP replacement	See line 85	67
§ 250.734 (a)(16)	BOP	Contributes to BOP replacement	See line 85	68
§ 250.734 (b)	BOP	\$48	\$4.8	69
§ 250.734 (c)	BOP	\$3.3	\$0.33	70
§ 250.735 (a)	BOP	\$48	\$4.8	71
§ 250.737 (d)	BOP	\$237	\$23.7	72
§ 250.737 (d)(5)	BOP	Cost is included in Parent Rule	See line 72	73
§ 250.737 (d)(12)	BOP	Cost is included in Parent Rule	See line 72	74
§ 250.737 (d)(13)	BOP	Not currently calculated		75
§ 250.738 (b)	BOP	Not currently calculated		76
§ 250.738 (j)	BOP	Not currently calculated		77
§ 250.738 (o)	BOP	\$48	\$4.8	78
§ 250.738 (p)	BOP	Not currently calculated		79
§ 250.739 (b)	BOP	\$8,968	\$897	80
§ 250.743 (c)	Well Design	\$0.433	\$0.043	81
§ 250.746 (e)	BOP	\$123.8	\$12.4	82
Safe Drilling Practices	RTM	Real Time Monitoring	See line 41	83
Shearing Requirements	BOP	Contributes to BOP replacement	See line 85	84
BOP Replacement (Result of Multiple Regulations)	BOP	\$2,080	\$208	85
Packer and Bridge Plug Inventory Loss (Result of Multiple Regulations)	Tubing and wellhead equipment	\$32.1	\$3.2	86
BSEE Approved Verification Organization	BAVO	BSEE Approved Verification Organization	See Footnote 5	87
Total		\$31,830.5	\$3,183.1	88

⁵ BSEE Approved Verification Organizations (BAVO) are not defined by the regulations and do not currently exist as proposed by the rule. As such it is not possible to calculate the cost that the involvement of these organizations will entail or other possible effect.

Estimated costs are identified by rule section, subsection, or, when necessary, individual line item where multiple regulations cumulatively contributed to an effect. For more specific explanations and analysis of the regulations cited in this table please see section 8, BSEE Rules and Regulations Appendix. The cost of regulations is calculated based on Quest's "Base Development Scenario" for the Gulf of Mexico and is the projected activity levels for various offshore oil and natural gas related activities based on current regulations without the proposed rule. Actual direct costs are likely to be lower due to wells not drilled due to the rule. This is discussed in section 5, Impact on Development.

The average annual costs to industry participants of the proposed rule are projected at around \$3.2 billion per year from 2017 to 2026. Cumulative 10-year costs are estimated at over \$32 billion. (Figure 2)

Figure 2: Estimated Annual Cost Rule by Category - 2017 to 2030 (\$Millions)



Source: Quest Offshore Resources, Inc.

Costs are projected to rise rapidly in the early years of adoption due to implementation costs and the required replacement of equipment through years 5-7, before falling beginning in 2022 as implementations costs and the replacement of equipment slows. Costs begin to rise again in 2025 as those costs that are closely tied to activity levels (especially well costs) increase with activity levels. Additionally, certain areas of operations are expected to carry higher costs than others. For example, costs associated with well design regulations are projected at over \$1.6 billion per year from 2017 to 2026 a total of over \$15.6 billion over the same period, while costs associated with changes to BOP regulations are projected at just over \$1.2 billion a year from 2017 to 2026 for a total of \$12 billion over the same period. (Table 6)

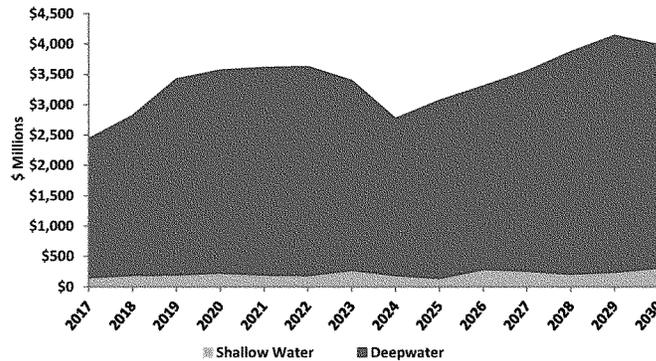
Table 6: Ten Year Direct Cost Estimates – Base Development Case (\$Millions)

Category	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
BOP Replacement or Modification	\$925	\$926	\$1,336	\$1,331	\$1,373	\$1,465	\$1,419	\$978	\$1,041	\$1,052	\$11,846
Compliance and Documentation	\$11	\$12	\$11	\$12	\$13	\$13	\$14	\$13	\$12	\$15	\$127
Containment	\$113	\$114	\$179	\$181	\$190	\$99	\$97	\$98	\$85	\$86	\$1,241
Rig Requirements	\$204	\$205	\$205	\$215	\$239	\$239	\$240	\$244	\$247	\$250	\$2,288
Real Time Monitoring (RTM)	\$74	\$72	\$73	\$85	\$83	\$52	\$56	\$63	\$63	\$50	\$670
Tubing and Wellhead Equipment	\$33	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$38
Well Design	\$1,062	\$1,470	\$1,597	\$1,721	\$1,691	\$1,739	\$1,551	\$1,357	\$1,601	\$1,830	\$15,620
Grand Total	\$2,421	\$2,800	\$3,402	\$3,547	\$3,589	\$3,606	\$3,378	\$2,753	\$3,050	\$3,284	\$31,831

Source: Quest Offshore Resources, Inc.

Although the proposed rule is expected to increase costs for wells and projects in all water depths in the Gulf of Mexico, the effect is expected to be felt disproportionately in deep and ultra-deep water depths, areas which carry a disproportionately higher operating cost and are projected to account for the majority of activity in the region. (Figure 3) Under the base development scenario, average annual costs for deepwater activity are projected to increase by over \$3 billion a year from 2017 to 2026, with total cumulative costs of \$30 billion from 2017 to 2026. Increased costs for shallow water activity are projected to be around \$200 million dollars annually, with cumulative costs from 2017 to 2026 projected at nearly \$2 billion.

Figure 3: Estimated Annual Costs Deepwater vs. Shallow Water – Base Development Scenario (\$Millions)



Source: Quest Offshore Resources, Inc.

Increased costs, coupled with wells and projects not able to be developed, are expected to have a significant effect on Gulf of Mexico OCS activity levels in the forecasted period, with effects from this

reduced activity level felt in employment, GDP, and other indicators. These effects are described in the following sections of the study, section 5, impact on Development and section 6, Macro-Economic Impact Conclusions.

3.1 Ten Year Cost Comparison – Study Estimates vs. BSEE

Although the cost impacts associated with the proposed rule "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control" developed by this study were developed independently and without reference to additional studies analyzing the proposed regulatory changes and effects, the following table provides a ten year cost comparison to BSEE's own cost impact study for reference. It is important to note that due to the time limitations associated with this study, both additional costs and possible cost savings calculated by BSEE, are not included in this study. Additionally, as this study projects that costs associated with this study will begin to be required in 2017, the reference year (year 1) for this cost comparison is 2017 for this study compared to 2015 for the BSEE analysis. It is also important to note that both the BSEE cost analysis and that provided by this study take into account the varied implementation timelines of the proposed regulations and both studies do not address the costs associated with the proposed rule. (Table 7)

Table 7: BSEE Ten Year Cost Comparison Table (\$Millions)

Year	BSEE Estimates	Study Estimates
Year 1	\$165	\$2,421
Year 2	\$77	\$2,800
Year 3	\$77	\$3,402
Year 4	\$77	\$3,547
Year 5	\$77	\$3,589
Year 6	\$99	\$3,606
Year 7	\$77	\$3,378
Year 8	\$77	\$2,753
Year 9	\$77	\$3,050
Year 10	\$77	\$3,284

Source: Quest Offshore Resources, Inc.

The overall industry-incurred cost due to the proposed rule change within the first ten years of implementation of the studies displays significant divergence, under which Quest has predicted an average of around \$3.2 billion per year while BSEE foresees \$120 million per year. Furthermore, Quest also projects additional industry effects throughout the supply chain due to the inability to develop numerous projects, which are then removed from the forecast.

Allocation of Costs

This study does not attempt to allocate the projected costs associated with the adoption of the proposed rule to specific industry participants due to the difficulty of that process. Each of the individual rules' effects are likely to be felt by numerous groups of industry participants and the specific allocation of these costs is unlikely to be accurately predicted. However, the vast majority of the costs associated with

the proposed rule are expected to affect certain groups disproportionately. As an example, the costs associated with rules affecting subsea blow out preventers are expected to be borne primarily by drilling contractors operating floating drilling rigs and the limited number of original equipment manufacturer who manufacture these pieces of equipment. In comparison, the costs associated with rules which are focused on well construction are expected to be borne mostly by oil and natural gas operators with the majority of the cost borne by the limited operators active in deep and ultra-deep waters. Implementation of the proposed rule as currently written would likely also lead to a change in the operators and contractors active in the Gulf of Mexico OCS, as smaller companies may reduce participation in the area due to the increased costs. Therefore while this study does not specifically allocate costs to specific industry participants it is important to emphasize that the costs of the regulations will be primarily borne by those industry participants engaged in the types of activity most affected by the proposed rule.

Containment Costs Already Borne by Industry

The increased costs resulting from the adoption of the proposed rule, calculated above, exclude many costs already borne by the industry which would not be required prior to the implementation of the proposed rule. The largest single investment by oil and natural gas operators and contractors has been on containment equipment including subsea capping stacks, storage equipment, and vessels to deploy this equipment and process contained fluids. Neither this investment, nor the impacts of that spending are included in the costs above nor are the employment or GDP impacts, as they were not required prior to the proposed rule. However, the study includes an estimate of this spending for reference. The industry has invested in two separate containment systems, organized as the Marine Well Containment Company (MWCC) and the Helix Well Containment Group (HWCG). Both of these systems have required significant upfront investment as well as ongoing spending. MWCC and its member companies have spent an nearly \$1.5 billion since its founding, with investment in two tankers designed to process oil and gas, multiple capping stacks and a variety of other equipment. HWCG, which has utilized some existing equipment such as the Helix Q4000 and the Helix Producer 1 has, with its member companies, invested approximately \$780 million into well containment preparation since its founding. Beyond equipment, the costs associated with these containment organizations range from shorebases, to preposition equipment, to training for the utilization of the equipment and continued maintenance.

Effect on Other U.S. OCS Areas

Although the costs and other impacts associated with the proposed rule are calculated solely as it effects Gulf of Mexico OCS activity, the rule will affect all U.S. Federal OCS areas including Alaska, existing production on the Pacific coast and any future activity in areas where oil and natural gas exploration activity is not currently taking place. These areas include the Atlantic coast (where there is a currently proposed lease sale expected to take place in 2021 in limited areas of the central and southern Atlantic coast), the Eastern Gulf of Mexico, and areas of the Pacific coast which are currently closed to new oil and natural gas activity. Although many of the costs associated with the proposed rule would be similar to those stemming from the rule in the Gulf of Mexico, other costs would likely be higher, especially on a per-well or per-project basis. The section of regulation most likely to see higher costs in new areas (such as the Atlantic coast) is projected to be containment, as the prepositioning of materials,

capping stacks and vessels for operations in the Atlantic would likely be spread over far fewer wells and projects, especially initially.

Cost Effects of Proposed Regulations

The detailed technical and economic analysis of the projected costs of the proposed rule “developed in this study indicate that the effects of the adoption of this proposed rule would likely impose a significant burden on participants in the Gulf of Mexico OCS oil and gas industry. In addition, these costs and requirements are likely to reduce overall OCS oil and natural gas development relative to what is projected to occur with current regulations. The lost activity is due to increased costs which may make some wells or projects uneconomic, delays reducing the number of wells drilled per year, and the inability to drill certain wells or develop certain projects and meet new technical requirements of the rule. The projected impact of the proposed rule on Gulf of Mexico oil and natural gas development and the subsequent impacts on spending by the industry, oil and natural gas production, employment, GDP and government revenues are discussed in the next section.

Section 4 - Impact on Development

Natural gas and crude oil exploration and production activities offshore of the US provide large contributions to employment, gross domestic product and state and federal government revenues. To quantify the effects of the proposed rule, the study forecasted activity levels for Gulf of Mexico OCS oil and gas activity with and without the proposed rule. The forecasted activity levels include the number of wells drilled, projects executed, total production, and spending. These activity forecast drive the spending projections from which GDP, employment and government revenue effects are estimated.

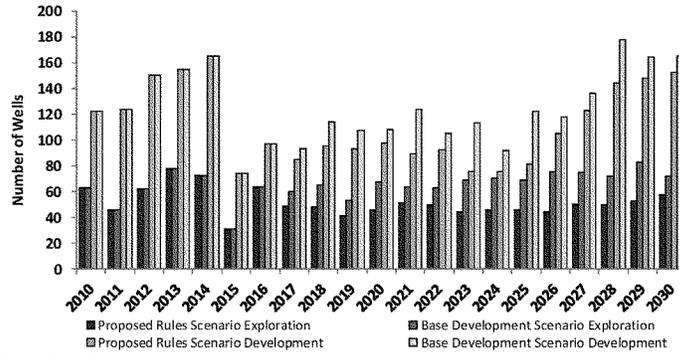
4.1 Wells Drilled

Exploration appraisal and development drilling is used to identify, confirm, delineate, and produce oil and natural gas, making it one of the most important offshore oil and natural gas activities. Drilling is a very capital intensive process employing drilling rigs that require large crews as well as significant quantities of consumables ranging from food and fuel to drill pipe and fluids. Drilling rigs (mobile offshore drilling units – MODU's) and platform rigs must constantly be resupplied and crewed, and thus lead to high levels of activity in the areas and ports that support offshore drilling activity.

Drilling activity in the US Gulf of Mexico is projected to continue to be robust throughout the forecast period as exploration of new geologic areas continues and development of the known production areas progresses. The region is projected to see around 960 exploration wells drilled and around 1740 development wells drilled between 2017 and 2030 under the current regulatory environment, and around 670 exploration wells and around 1335 development wells under the proposed rule scenario. This represents a 26 percent decrease in drilling activity over the study period.

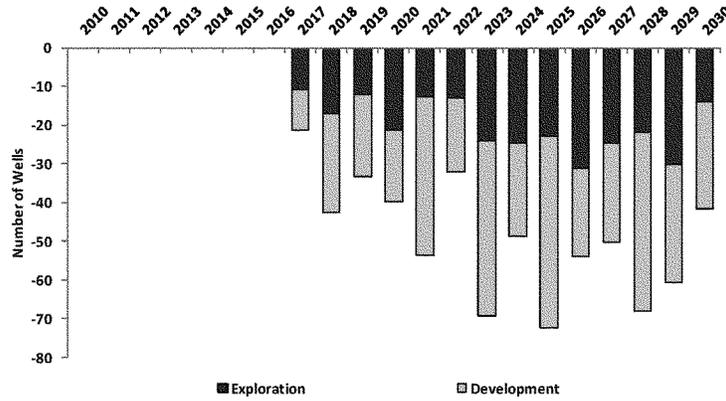
The decrease in drilling under the new regulations, as mentioned in the regulation section, is primarily due to the effects of §250.414, "Planned safe drilling margins" as well as higher costs associated with the regulations. Since many of the wells that are projected to be drilled in the Gulf are in particularly deep water, and located in high pressure, high temperature reservoirs, or are being drilled in depleted reservoirs, some of these wells are expected to be no longer technically possible to drill or complete under the new regulations, and others, particularly development wells, may become economically non-viable. The effects of the regulations, as written, are projected to have a significant influence on overall drilling levels (Figure 4). The proposed rule scenario results in an average of around 20 less exploration wells drilled per year and around 29 less development wells per year. (Figure 5)

Figure 4: Number of Wells Drilled by Well Type and Scenario - Exploration and Development



Source: Quest Offshore Resources, Inc.

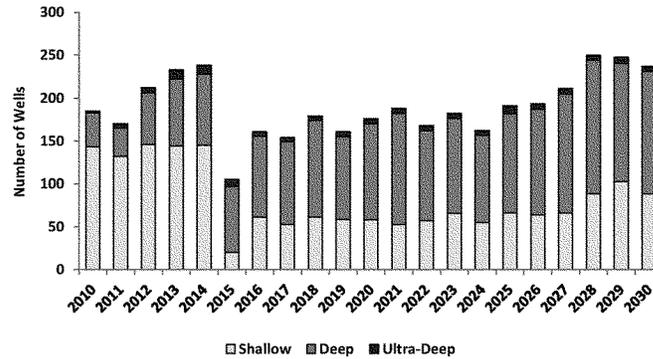
Figure 5: Difference between Number of Wells Drilled in Base Development and Proposed Rule Scenarios



Source: Quest Offshore Resources, Inc.

Drilling activity as a whole has shifted from primarily shallow water areas into progressively deeper and higher pressure areas, as the reservoirs in shallower areas mature and new fields are discovered. (Figure 6)

Figure 6: Number of Wells Drilled by Water Depth and Year – Base Development Scenario



Source: Quest Offshore Resources, Inc.

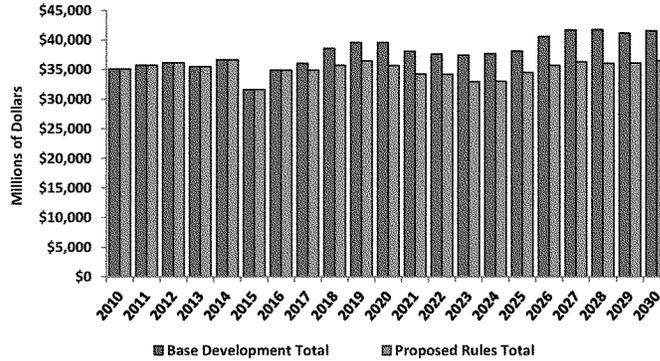
Under the base development scenario, a total of around 2,700 wells are projected to be drilled from 2017 to 2030, with three percent of wells projected to be located in ultra-deep water, 62 percent of the wells projected in deep water and 35 percent projected in shallow water. Under the new regulations, approximately around 690 fewer wells are projected to be drilled from 2017 to 2030, a 26 percent decline, with similar water depth distributions. Over the 10-year 2017 to 2026 period the projected number of wells projected not to be drilled equals around 470, with an average of 20 fewer exploration wells per year and 29 fewer development wells.

4.2 Projects Executed

Developing an offshore project is a complex process that requires a significant amount of time, planning and high levels of capital investment. Project executions and their respective timelines are the best indicator of overall market health, as they can be viewed as representative of total trends in production, employment and revenue for the broad market.

Over the forecasted period of this study (2017-2030), 15 standalone floating production projects and 49 fixed platform-based oil and natural gas projects are projected to begin production under the base development scenario. These projects and other additions to the existing projects in the Gulf collectively represent \$549 billion in capital and operational spending over the course of the forecast period. As a result of the burdens placed on project and drilling economics by the proposed rule scenario, the total number of floating production units developed is projected to decrease by 20% and fixed platforms are projected to decrease by nearly 33% under the new regulations. Collectively, this reduction in activity is projected to lead to a decrease in total spending of nearly 30 percent, which would be worth around \$52 billion. (Figure 7)

Figure 7: Total Yearly Project Spending by Scenario



Source: Quest Offshore Resources, Inc.

Total project spending is primarily driven by overall activity levels, and partially driven by the project design and size of the projects executed. Apart from water depth, project size is typically defined by reservoir characteristics, hydrocarbon volumes and expected production, which define the timeline and capital investment required to develop the project. Larger projects typically require more wells and a longer development period, in addition to requiring increased material resources and larger equipment such as platforms, production trees and pipelines. Smaller projects, on the other hand, often rely on larger projects for certain types of infrastructure such as pipelines or processing facilities. This leads to the spending, production and other effects on a per project basis to be highly variable.

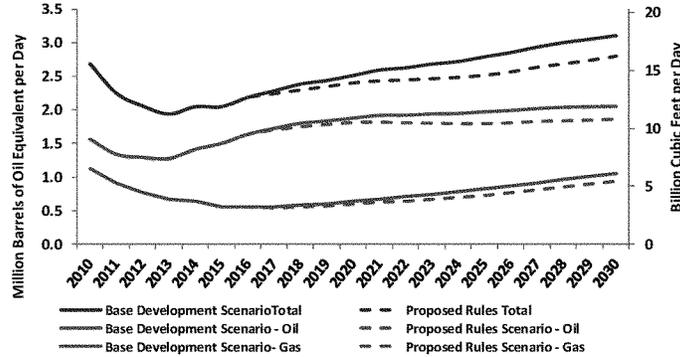
4.3 Production

The number of projects developed, coupled with reservoir size and reservoir productivity, is the main determinant of oil and natural gas production levels. Most oil and natural gas reservoirs contain a combination of oil, natural gas, water, and other native substances such as sand, sulphur, CO₂, and salt, though some reservoirs may contain nearly all oil or all natural gas. In order to forecast aggregate production, each project was modeled based on production curves for similar developments, taking into account the start-up, ramp-up, peak, and decline timing, as well as the expected hydrocarbon mix.

This study projects that production in the Gulf of Mexico will be around 2.28 million barrels of oil equivalent (BOE) per day in 2017 and is projected to grow relatively consistently throughout the period, at a compound annual growth rate of roughly 2.5 percent per year from 2017 to 2030. Production is projected to reach 3.10 million BOE per day by 2030, with approximately 66 percent of production oil (2.05 million BOE per day), and 34 percent of the production natural gas (1.05 million BOE per day). Under the proposed rule, Gulf of Mexico production is forecasted to be reduced by nearly 15% and 0.48 million BOE per day by 2030, with approximately 67 percent of production being oil (1.74 million BOE per day),

and 33 percent of the production being natural gas (739 thousand BOE) under the proposed regulations. (Figure 8)

Figure 8: Production by Type by Scenario - MMBOED 2010 to 2030



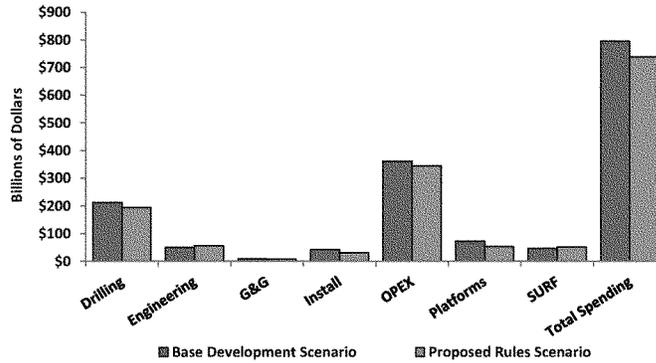
Source: Quest Offshore Resources, Inc.

4.4 Total Spending

Offshore oil and natural gas exploration and development is a capital intensive process. Offshore projects require exploratory seismic surveys, drilling, production equipment, engineering, operational expenditures including the ongoing supply of consumables, and maintenance as well as other spending to be found and developed. The total cumulative spending from offshore oil and natural gas development is projected to be nearly \$550 billion between 2017 and 2030 under the base case scenario and \$493 billion under the proposed rule, a yearly average of \$39.2 and \$35.2 billion respectively, which equals an average decline of \$4 billion per year. This represents a 10.3 percent decrease in total spending as a result of the proposed rule changes.

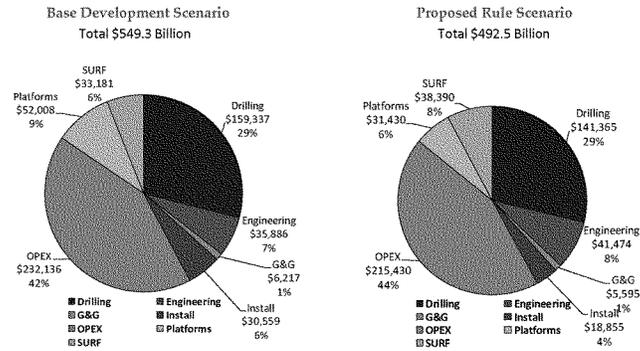
For the purposes of this report, spending is divided into seven main categories: Drilling, Engineering, G&G, Installation, OPEX, Platforms, and Subsea Umbilicals, Risers and Flowlines (SURF). Each category encompasses a major type of exploration and production activity and has a significant influence on overall spending. Both development scenarios estimate total spending amounts that rise slightly through the end of the decade, decline briefly, then recover due to normal project development cycles. Under the proposed rule case, very little spending growth is projected during the forecast period. (Figures 9 & 10)

Figure 9: Cumulative Spending by Category and Scenario – 2017 to 2030



Source: Quest Offshore Resources, Inc.

Figure 10: Share of Total Spending by Category and Case – 2017 to 2030 (\$Billions)

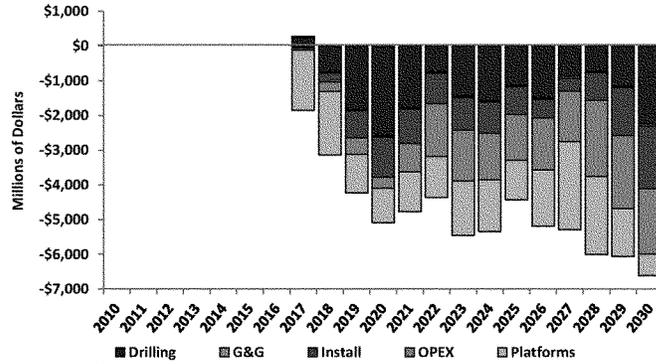


Source: Quest Offshore Resources, Inc.

The proposed rule is anticipated to increase some types of spending for Gulf of Mexico oil and natural gas development. However, increased spending due to compliance with the proposed rule is anticipated to be more than offset by reduced spending in areas that are impacted from fewer wells drilled and projects developed. Therefore, as a result of the proposed rule overall spending for Gulf of Mexico oil and natural gas activity is projected to decline.

The platform CAPEX, drilling, OPEX, installation, and G&G markets are all projected to see decreased spending under the proposed rule scenario, with average yearly spending decreases of \$1.47 billion, \$1.28 billion, \$1.19 billion, \$836 million and \$44 million respectively (Figure 11)

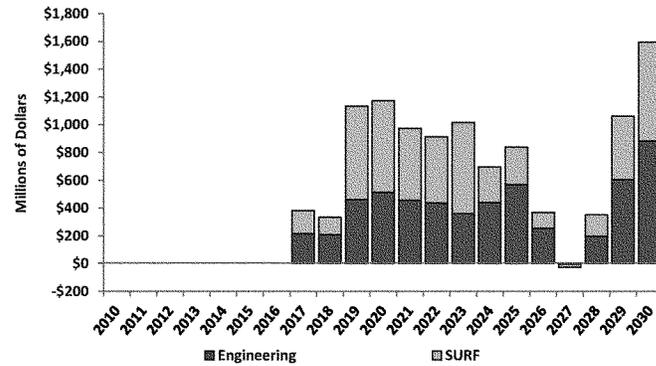
Figure 11: Projected Spending Decreases under Proposed Rule Scenario Spending by Category



Source: Quest Offshore Resources, Inc.

The platform Engineering and SURF markets are both projected to see increased spending under the proposed rule scenario, with average yearly spending increases of \$399 million and \$372 million respectively. A more detailed look at these market segments may be found below (Figure 12 & Table 8).

Figure 12: Projected Spending Increases under the Proposed Rule Scenario Spending by Category



Source: Quest Offshore Resources, Inc.

Table 8: Base Development and Proposed Rules Scenario Spending Comparison 2017 to 2030 (\$Millions)

Category	Annual Base Development Scenario (\$ Millions)	Annual Proposed Rules Scenario (\$ Millions)	Annual Net change in Spending (\$ Millions)	% Change in Spending
Drilling	\$11,381	\$10,097	-\$1,284	-11%
Engineering	\$2,563	\$2,962	\$399	16%
G&G	\$444	\$400	-\$44	-10%
Installation	\$2,183	\$1,347	-\$836	-38%
OPEX	\$16,581	\$15,388	-\$1,193	-7%
Platforms	\$3,715	\$2,245	-\$1,470	-40%
SURF	\$2,370	\$2,742	\$372	16%
Total	\$39,237	\$35,181	-\$4,056	-10%

Source: Quest Offshore Resources, Inc.
G&G

Seismic (G&G) spending is normally associated with imaging of possible reservoirs prior to exploration drilling and thus takes place primarily at the early stages of a project's lifecycle. Although critically important to long-term development, seismic spending is a relatively low percent of overall spending at an average of \$444 million per year, or roughly one percent of overall spending from 2017 to 2030 in our base development case, and \$399.6 million and around one percent per year in our proposed rule case.

Drilling

Given the expense and logistics requirements of offshore drilling, where rigs command significant day rates and operational costs, drilling expenditures represent one of the largest sources of spending for any offshore project. Total drilling costs from 2017 to 2030 for exploration and development drilling combined are projected to average nearly \$11.4 billion per year in the base development scenario and \$10.1 billion in the proposed rule scenario, indicating a \$1.3 billion decrease in activity due to a drop in well demand partially offset as a result of the increased costs of the proposed rule. Drilling accounts for 29 and 26 percent of each case's total spending respectively.

Engineering

Engineering spending takes place at all stages of an offshore project's lifecycle, including exploration, project development and the operational phase. These activities vary from overall project-focused engineering to the engineering of very specific equipment and components. Engineering spending is projected to average \$2.5 billion per year from 2017 to 2030 in the base development scenario. In the proposed rule scenario due to the engineering burdens necessitated by the regulation, engineering spending is projected to average \$3.0 billion per year. These spending categories account for around seven and eight percent of total spending in their respective cases.

Platforms & SURF

The majority of equipment utilized in developing offshore oil and natural gas fields can be found on either the platform (both fixed and floating) or subsea, as a part of the SURF (subsea equipment,

umbilicals, risers and flowlines) category. This equipment is purchased and constructed prior to production of oil and natural gas, though more can be added to a project after first production. The types of equipment include complicated structures like floating platforms that weigh tens of thousands of tons, complex subsea trees that control wells at the ocean floor and miles of pipeline that transport the produced oil and gas back to shore. In addition to these large, expensive pieces of equipment, some of the components required for offshore production are less complex (e.g. offshore accommodation modules, metal mats placed on the seafloor to hold other equipment, or stairwells).

Due to the varying timelines for procurement of equipment, spending for platforms and SURF equipment is more variable year to year than most other offshore exploration and development spending. Platform spending is projected to average over \$3.7 billion per year from 2017 to 2030 in the base development scenario and \$2.2 billion per year under the new regulations, due to decreased project activity. SURF spending is projected to rise under the new regulations due to increased per-well spending on the associated systems. Due to these effects, in the base case forecast \$2.4 billion are projected to be spent each year from 2017 to 2030, and in the proposed regulation case an average of \$2.7 billion of spending are projected to be attributable to SURF hardware and associated activity. These costs represent 6.0 and 7.0 percent of total spending in their cases respectively.

Installation Activity

The installation of platforms and SURF equipment is normally carried out by multiple vessels, each with specialized functions such as pipe-lay or heavy-lift. Some vessels might lay large diameter pipelines (14 inch+), while other vessels lay smaller diameter infield lines (2-10 inches) or lift equipment, and install hardware. Other specialized vessels supply drill-pipe, fuel and other fluids, and food. Nearly everything installed offshore must first be prepared onshore at specialized bases in the region prior to installation. Equipment is sometimes transported to the field on the installation vessels themselves, and at other times is brought to the field on specialized barges or transportation vessels. Installing offshore equipment often requires complex connection or integration operations and uses vessels that can command day rates of over \$1 million.

Due to lower project development activity in the proposed rule scenario, a significant decrease in installation activity is expected between the two cases for this subsection of the market. Between the 2017 and 2030 period, average annual installation spending is projected to be \$2.2 billion per year under the current regulatory environment and over \$1.3 billion under the proposed regulations, representing around six percent and just over three percent of total spending in each of the cases.

OPEX

Once the initial wells have been drilled and the necessary equipment installed, a field enters the operational phase, which requires manning and operating facilities and equipment, continuously supplying essential fluids and constant general maintenance. Due to the maturity of the market and the large amount of existing infrastructure, these operational expenditures (OPEX) are a significant source of ongoing spending by oil and gas companies within the region. However, much of the aging infrastructure

in the Gulf is being removed, allowing expenditures on many assets to be rolled back or even stopped. In the base development scenario, operational expenditures are projected to decrease from over \$17.6 billion in 2017 to \$16.2 billion by 2030, mostly driven by a decrease in shallow water OPEX, which is offset by increasing deepwater OPEX. In the proposed rule scenario, there is less new activity to offset the decline, and the trend is even more pronounced. OPEX spending under the new rules is projected to decline from \$17.6 billion to \$14.2 billion per year, averaging \$15.4 billion over the forecast period.

Section 5 - Macro-Economic Impact Conclusions

In order to further quantify the effects of the proposed rule, Quest constructed an economic analysis model to estimate changes in jobs, GDP, and governmental revenue. The estimates created throughout this section closely parallel spending and activity trends. Employment and GDP effects are calculated using the most recent Bureau of Economic Analysis' (BEA) RIMS II models in order to quantify the effects of domestic spending.

This analysis further underscores that the economic benefit of increased spending due to the adoption of the proposed rule as written will likely be outweighed by overall reductions in oil and natural gas exploration and development. The net economic analysis anticipated from the proposed rule is projected to result in significant declines in employment, GDP, and federal revenue from 2017 forward.

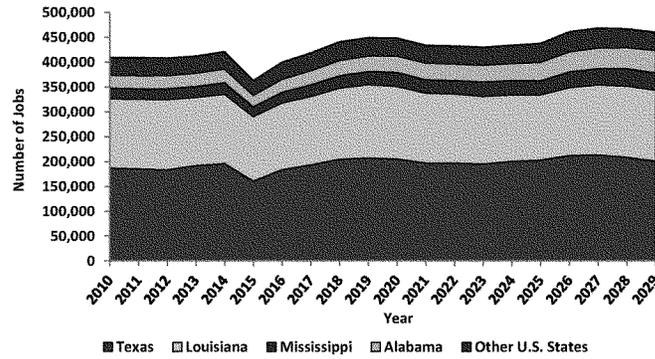
5.1 Employment

The offshore oil and gas industry has a long history of significant employment throughout the nation and in particular in the Gulf Coast states. Continued investment in offshore infrastructure has built a buoyant and diverse supply chain that has historically provided high wages to significant numbers of white and blue collar laborers. Most recent estimates through Quest's application of the BEA economic models have suggested that total employment supported by industry spending is approximately 363 thousand in 2015 with nearly 142 thousand direct industry jobs and an additional 220 thousand jobs provided from indirect and induced industry spending⁶.

Employment is expected to grow throughout the forecast, as continued project investment, particularly in deep and ultra-deep waters is projected to lead to employment growth throughout the region. Gulf of Mexico OCS activity-driven employment within the U.S. is likely to grow from 363 thousand jobs in 2015 to more than 466 thousand by 2030, which equals an additional 104 thousand jobs and represents 29 percent growth. No major shifts are expected within the state employment distribution, as Texas and Louisiana are expected to continue to be the most significant beneficiaries of offshore oil and gas with 160 thousand and 130 thousand jobs in 2015 respectively, and 202 thousand and 145 thousand jobs projected by 2030. (Figure 13)

⁶ Indirect jobs are those related to the oil and natural gas supply chain. Induced jobs are created from more income that is spent throughout the economy.

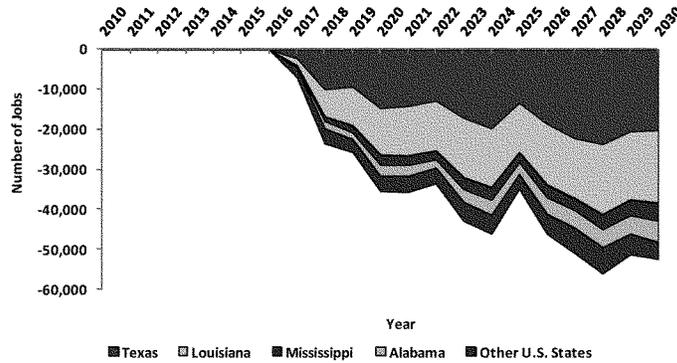
Figure 13: Jobs by State - Base Development Scenario



Source: Quest Offshore Resources, Inc.

With the proposed rule, yearly employment supported is projected to diverge from the base forecast, continuing to widen in the later years with over 50 thousand yearly jobs displaced through lost offshore activity by 2030. Gulf of Mexico oil and natural gas development is projected to support fewer jobs with the proposed rule despite increases in spending by the industry to meet the rule's requirements. This is due to fewer wells drilled and lower overall spending. (Figure 14)

Figure 14: Jobs by State - Proposed Rule Scenario Difference



Source: Quest Offshore Resources, Inc.

This lower employment level is likely to primarily affect the Gulf Coast, with Texas and Louisiana expected to see employment levels of 20 thousand and 18 thousand jobs lower by 2030. This represents ten percent and 12 percent lower projected Gulf of Mexico OCS oil and natural gas production employment respectively. (Table 9)

Table 9: Estimated Total Supported Employment Levels by Scenario – 2010 to 2030

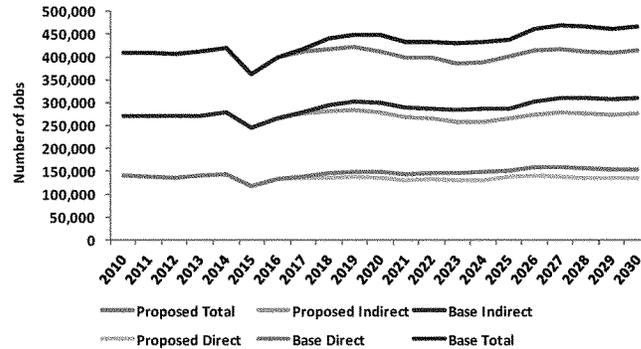
Case	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case	409,484	409,165	408,102	412,231	421,157	362,797	399,745	418,592	440,788	449,152	448,591
Proposed Rule	409,484	409,165	408,102	412,231	421,157	362,797	399,745	411,674	417,244	423,443	413,102
Difference								(6,918)	(23,544)	(25,709)	(35,488)

Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Case	433,967	432,658	429,997	434,125	437,702	461,102	468,727	467,236	460,408	466,541
Proposed Rule	398,256	399,091	387,026	387,946	402,826	414,877	417,656	411,089	409,033	414,002
Difference	(35,731)	(33,567)	(42,972)	(46,179)	(34,875)	(46,225)	(51,071)	(56,147)	(51,376)	(52,539)

Source: Quest Offshore Resources, Inc.

The BEA's RIMS II model allows the calculation of employment estimates for both direct jobs, (employment for those that work within the industry) and indirect and induced jobs (those created through the network of oil and gas operations as well as ancillary spending from the industry and its employees). Estimates for direct job numbers are expected to grow from 118 thousand to 154 thousand between 2015 and 2030, a 31 percent growth, while indirect jobs are expected to grow from 244 thousand to 311 thousand, a 27 percent growth. (Figure 15)

Figure 15: Direct vs. Indirect/Induced, and Total Employment – Base Development Scenario vs. Proposed Rule Scenario

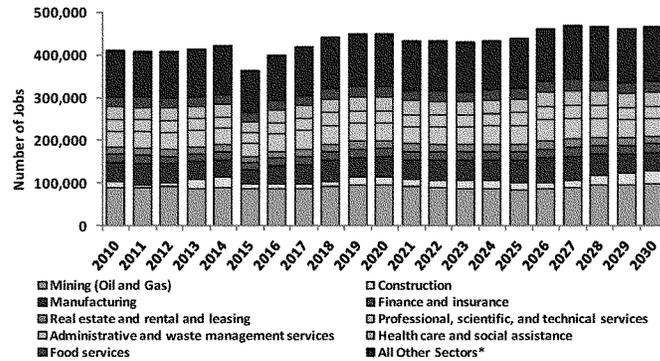


Source: Quest Offshore Resources, Inc.

The impacts of the proposed rule are expected to have the largest numeric effect on indirect jobs, with an expected net loss of 34 thousand jobs or a 12 percent reduction to the base case, while direct jobs are expected to see a smaller, net loss of 18 thousand jobs or 14 percent of projected employment in 2030.

The current offshore oil and gas supply chain has grown to include suppliers throughout the country and world and a multitude of companies. Development of offshore oil and natural gas projects involves a larger number of industries, which include, but are not limited to: mining (of natural resources including oil and natural gas production), manufacturing, professional, scientific, and technical services (engineering), manufacturing, and construction (installation). Combined, these industries are expected to see additional employment of around 50 thousand jobs by 2030, with employment growing from 162 thousand to 212 thousand jobs. Additional industrial sectors that benefit indirectly through induced employment are likely to see continued benefits throughout the study period due to Gulf of Mexico oil and natural gas development. These industries include among others, retail, finance and insurance, food services, and health care and social assistance. Employment in these industry sectors alone due to Gulf of Mexico oil and natural gas activities account for 25 thousand jobs on average in 2015 and is projected to reach 30 thousand jobs on average in 2030 under current regulations. (Figure 16)

Figure 16: Jobs by Profession - Base Development Scenario

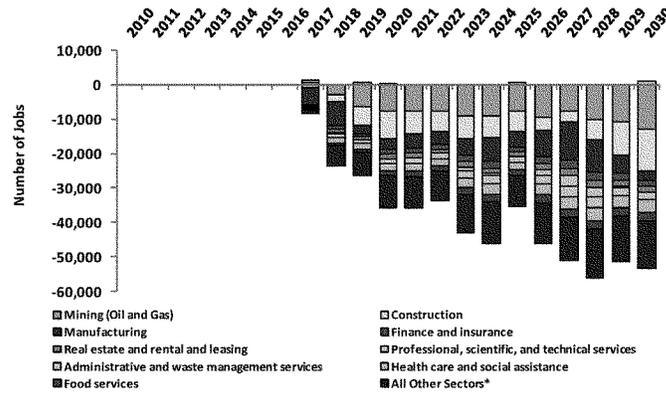


Source: Quest Offshore Resources, Inc.

The proposed regulations will have far reaching effects throughout the Gulf Coast economies as employment levels due to Gulf of Mexico oil and natural gas activities are projected to be 50 thousand lower as early as 2027 relative to employment projections under current regulations. These jobs are expected to be numerically focused within mining (oil and gas) and manufacturing, with both sectors seeing lower employment of around 12 thousand jobs in 2030. The construction (installation) sector has the largest employment impact proportionately over the study period, with a 44 percent decline in

projected employment as the costs of the proposed rule slow new project development activity. Numerous other industries are likely to see declines in projected employment of around 10 percent within their professions while professional, scientific, and technical services (engineering) are expected to see slightly higher employment in certain years due to the increased engineering burden of the proposed rule. (Figure 17)

Figure 17: Jobs by Profession – Delta Proposed Rule Scenario Difference



Source: Quest Offshore Resources, Inc.

5.2 GDP (Gross Domestic Product)

Potential gross domestic product (GDP) effects were calculated as a multiplier on spending within the U.S., further utilizing the BEA’s RIM II model. The estimated effects of proposed rule changes are therefore likely to be strongly correlated to any shifts within spending, with international spending (mainly on platform fabrication) excluded, and should mirror the shifts throughout employment.

The current GDP impact of the Gulf of Mexico offshore oil and natural gas industry in the U.S. is estimated at \$34.5 billion annually, and is projected to continue to grow to around \$40 billion over the forecast period by 2030 – representing around 16 percent growth. The proposed rule, if enacted as written, is projected to lead to the GDP impact from Gulf of Mexico oil and natural gas activities being \$4 billion lower in 2030. The cumulative 10-year loss of GDP from 2017 to 2026 is estimated at \$27 billion (Table 10).

Table 10: Estimated GOM Supported GDP by Scenario – 2010 to 2030 (\$Millions)

Case	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case	\$34,726	\$35,098	\$35,311	\$34,998	\$35,946	\$31,350	\$34,513	\$36,077	\$38,084	\$38,862	\$38,699
Proposed Rule	\$34,726	\$35,098	\$35,311	\$34,998	\$35,946	\$31,350	\$34,513	\$34,726	\$36,937	\$37,817	\$36,857
Difference	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$1,351)	(\$1,147)	(\$1,045)	(\$1,841)

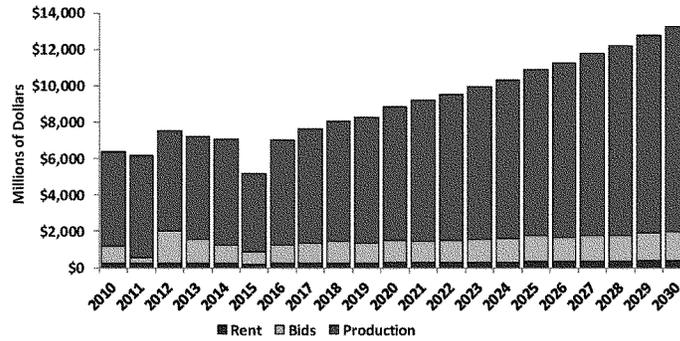
Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Case	\$37,332	\$36,991	\$36,661	\$36,948	\$37,330	\$39,618	\$40,400	\$40,297	\$39,641	\$40,141
Proposed Rule	\$35,099	\$34,186	\$33,523	\$33,819	\$34,297	\$35,281	\$35,900	\$36,851	\$35,682	\$36,133
Difference	(\$2,233)	(\$2,805)	(\$3,138)	(\$3,130)	(\$3,034)	(\$4,337)	(\$4,500)	(\$3,445)	(\$3,960)	(\$4,007)

Source: Quest Offshore Resources, Inc.

5.3 Government Revenue

Government revenues due to Gulf of Mexico offshore oil and gas operations are currently collected through three main revenue streams; revenue from lease sales, lease rental rates, and production royalties. The distribution of these revenues streams is heavily skewed towards production royalties, which account for around 80 percent of revenues from offshore oil and natural gas activities. Total government revenues from Gulf of Mexico offshore oil and gas royalties have been between \$5 and \$8 billion in recent years, lease sale revenues have been between \$300 million and \$1.5 billion, lease rental revenues have been approximately \$200 million per year, and production revenues have provided \$5 billion per year. (Figure 18)

Figure 18: Projected Governmental Revenues – Base Development Scenario



Source: Quest Offshore Resources, Inc.

Under the base development scenario, future lease sale levels are expected to remain in line with recent lease sale levels in the region. A minor decrease in the uptake rate due to decreasing lease

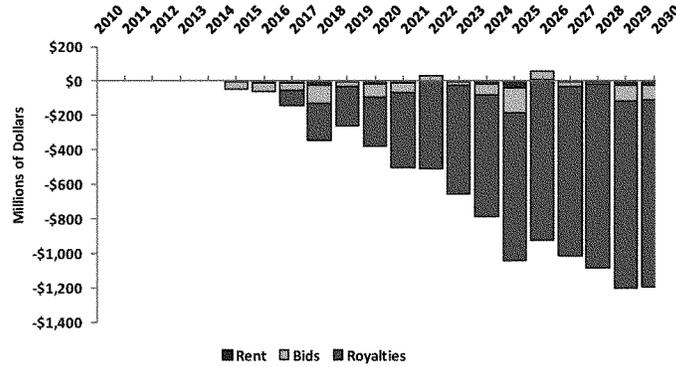
availability and expected recoverable reserves is projected to leave lease sales relatively flat, ranging from \$1 to \$1.5 billion each year over the forecast period. Block rentals account for the smallest portion of government revenue and are projected to fluctuate between \$200 and \$400 million per year over the forecast. Production royalties, calculated using the EIA long term oil and gas price forecast, continue to grow over the forecast due to increasing production, growing from a recent low of \$4.2 billion in 2015, driven by low oil prices, to more than \$11 billion in 2030. Production royalties will likely increase as projects with royalty rates on more recent leases with high tax rates come on stream throughout the forecast.

State and Federal governments share in the revenue from the GOM oil and natural gas development. Under GOMESA⁷ regulations instituted in 2007, state and federal regulators proposed a splitting of offshore revenues between state and federal governments. The second phase of the GOMESA rule will take effect in 2017 which will lead to an approximately a 62.5% to 37.5% split between state and federal governments with revenue capping provisions at \$500 million for states.

In parallel with previous section, the effects of the proposed rule are estimated to lead to lower government revenues of around \$18.5 billion from 2017 to 2030. Increased costs and lower recovery rates are expected to drive lower lease sales through the period, though growth within leases is expected, with the value of leases sold rising from \$650 million in 2015 to \$1.5 billion in 2030, while rental rates rise from \$180 million to \$350 million. The total estimated decline in combined rental and bid revenue due to the proposed rule is approximately \$1 billion over the life of the study. Production revenues are expected to rise from 2017 levels even under the proposed rule scenario, especially due to higher oil prices, though the growth is limited in comparison to the base development scenario. Under the proposed rule, revenues rise from \$4.3 billion in 2015 to \$9 billion in 2030, which is more than \$2 billion less than the base case total and represents a drop of nearly 15%. The estimated lost revenue from production royalties will provide the largest portion of potential lost revenues, estimated at around \$17.7 billion from 2017 to 2030. The cumulative 10-year loss of government revenue from 2017 to 2026 is estimated at \$9.9 billion (Figure 19).

⁷ Gulf of Mexico Energy Security Act of 2006 (Pub. Law 109-432) – was instituted to update the visibility on leasing activities as well as revenue sharing between state and federal governments.

Figure 19: Governmental Revenues – Proposed Rule Scenario Difference



Source: Quest Offshore Resources, Inc.

The revenue effects at the state level are expected to be minimal as GOMESA limits of \$500 million per year are reached under both revenue scenarios under Quest's interpretation of the law. (Table 11)

Table 11: Estimated State and Federal Government Revenues from GOM Oil and Natural Gas by Scenario 2010 to 2030 (\$Millions)

Case	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case	\$6,361	\$6,177	\$7,515	\$7,219	\$7,079	\$5,177	\$7,013	\$7,625	\$8,050	\$8,262	\$8,828
Proposed Rule	\$6,361	\$6,177	\$7,515	\$7,219	\$7,079	\$5,177	\$7,013	\$7,389	\$7,533	\$7,746	\$8,110
Difference	\$0	\$0	\$0	\$0	\$0	(\$0)	(\$0)	(\$236)	(\$517)	(\$516)	(\$719)

Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Case	\$9,188	\$9,518	\$9,953	\$10,307	\$10,909	\$11,247	\$11,780	\$12,222	\$12,777	\$13,254
Proposed Rule	\$9,267	\$8,557	\$8,740	\$8,889	\$9,164	\$9,580	\$9,865	\$10,148	\$10,488	\$10,870
Difference	(\$921)	(\$961)	(\$1,213)	(\$1,418)	(\$1,745)	(\$1,667)	(\$1,915)	(\$2,074)	(\$2,289)	(\$2,385)

Source: Quest Offshore Resources, Inc.

Section 6 - Conclusions

The oil and gas industry in the Gulf of Mexico has a tremendous influence on the local economies of the Gulf coast and the broader U.S. economy by supporting well-paying employment for hundreds of thousands of Americans, by providing revenues to many levels of the U.S. government and by contributing to the country's energy needs. The industry has grown into the world leader in offshore safety, technology, and scientific research. The shallow and mid-water Gulf production areas have been longstanding sources of employment and production, though those areas have been struggling to overcome the economic barriers of production in now-mature fields, and production has been in decline. Recently, efforts to revitalize mature fields and a shift towards production and activity in deepwater areas of the region have led to renewed activity in the Gulf of Mexico OCS, which is poised to reverse the long-standing trend of decline in offshore production volumes that began in the 1980s. Due to the work being done in the deepwater Gulf of Mexico, the industry's global influence has grown steadily, along with the economic benefits which it brings. The health of the industry is not, however, guaranteed. A lingering low-price environment and the steadily increasing difficulty and cost of producing oil and gas assets in the Gulf of Mexico have strained project economics and threatened the health of the industry.

While some part of the proposed rule, "Oil and Gas and Sulphur Operations in the Outer Continental Shelf – Blowout Preventer Systems and Well Control", are expected to have little or no negative affect on the industry, others will, in their current forms, seriously limit the ability of operators, drilling contractors, and service providers to safely, effectively, and economically operate in U.S. offshore areas, and may make the cost of producing currently economic wells prohibitively high or technically impossible. This decrease in activity and increase in cost will further damage an important industry that is already dealing with the repercussions of a volatile and challenging commodity price environment and may seriously impact the overall U.S. economy.

After analyzing the operational and economic impacts of the regulations, as proposed by BSEE, this study has projected that the following effects will result from their implementation:

- The 10-year costs estimates for the proposed rule from 2017 to 2026 are estimated to be over \$32 billion compared to a BSEE estimate of \$882 million. Most of these costs are attributable to well design requirements and BOP spending.
- When compared to the Base Development Scenario, the decreases in activity caused by these regulations are projected to reduce employment by over 50 thousand jobs as early as 2027 relative to jobs supported under current regulations. This is an estimated decrease of 11% of the projected employment due to the Gulf of Mexico oil and natural gas industry.
- If the proposed rule were to be enacted as currently written, annual capital investment and other spending directly related to offshore oil and natural gas development in the Gulf of Mexico OCS is projected to decrease from \$41.5 billion per year in 2030 to \$36.5 billion per year in 2030.

Cumulative capital investments and other spending from 2017 to 2030 are projected to decrease by nearly \$57 billion, a more than 10% drop.

- Between 2017 and 2030, the proposed rule is expected to decrease overall activity significantly in the Gulf, including:
 - A reduction in oil and natural gas production of 0.5 Million Barrels per day or 15.5% (from an average production of 3.10 Million BOE per day to 2.62 Million BOE per day),
 - A 26% decline in the number of wells drilled (from roughly 2,700 to 2,000),
 - 4% fewer leases (Dropping from 6350 to 6100), and
 - 13% less government revenue decreasing from \$144 billion to \$125 billion (The cumulative 10-year loss of government revenue from 2017 to 2026 is estimated at \$9.9 billion).
- The effect that domestic offshore oil and gas exploration and production are expected to have on US Gross Domestic Product is expected to be \$44 billion lower under the proposed regulations, which is 9% lower than the previous effect. The ten year GDP cost burden of the proposed rule from 2017 to 2026 is estimated at \$27 billion.
- It is clear that the proposed rule as currently written will have a significant effect on US employment, GDP, government revenues and domestic energy security due to increased costs borne by industry participants and reduced activity levels.

Section 7 - BSEE Rules & Regulations Appendix

This Report provides an independent high-level review and evaluation of the United States Department of Interior Bureau of Safety and Environmental Enforcement ("BSEE"), proposed rule on "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control" as published in the Federal Register Vol. 80 Friday, No. 74 on April 17, 2015 (the "Proposed Rule"). The purpose of this Report was to provide a summary of the most impactful sections and subsections of the Proposed Rule. This study is in no way exhaustive - especially in light of the quite short period available to review the Proposed Rule, the highly technical nature of these regulations, and time to develop this analysis with comments.

This Report reviewed key technical effects expected by the Proposed Rule on industry operations, and included those key technical effects within a larger evaluated economic analysis of the Proposed Rule on offshore resource development. The larger economic analysis viewed across stakeholders, including the industry operators, industry support providers (i.e. engineers, designers, manufacturers, service, and equipment suppliers), government revenue losses, and resultant employment effects. The key technical effects were reviewed by Blade Energy Partners, and the economic analyses and evaluation was provided by Quest Offshore Resources.

The analysis in this Report focuses on the likely engineering and operational effects of these regulations, and wherever possible attempts to calculate the cost of overcoming these burdens. As such, this analysis is essentially forward looking, and therefore subject to significant changes based on the final rules as implemented by BSEE, the way in which the final rules are implemented, and a variety of other factors. However, this Report's authors believe that this approach is the best available way to consider this rule (as more a backwards looking review based on previous industry activity would likely overstate the effects of these regulations). Similarly, a more narrow view of the regulations which focuses solely on the narrow cost of implementing individual rules without taking into account the engineering and operational burdens imposed by the regulations is likely to underestimate the projected costs of their implementation. Due to the limited time available to prepare this Report, as well as significant uncertainties about the way the Proposed Rule would be implemented if enacted, the projected costs and engineering and operational burdens for all proposed regulations are not included in this Report. Additionally, the internal costs to BSEE of implementing and administering the proposed rule are not calculated in this Report. Due to the conservative approach and the time limitations associated with this study it is likely that the full costs and economic impacts presented in this report underestimate the overall impacts of the proposed rule.

The Report's authors make no representation as to the effects of proposed regulations not addressed specifically in this report, and do not discount the possibility that these proposed changes could impose additional significant engineering, operational or other burdens on industry, regulators or others. The Report's authors' estimates herein of the effects that BSEE's Proposed Rule will have on current and future engineering and operations and technology advances are an independent good faith

qualitative view arising from unfortunately short considerations by various subject matter persons within Quest Offshore (an independent consulting firm focused on offshore oil and gas operations and economics) and Blade Energy, (a consulting company in well design, engineering and operations. If BSEE extends the comment period for the Proposed Rule, then further consideration of the effects the Proposed Rule will have on industry resource development may be requested. The future effects of these Proposed Rule on new, emerging, and likely technologies and methods cannot be evaluated properly within the time frame of this Report effort.

As this was an independent review, industry and others (operators, original equipment manufacturers, support and service providers) may, and surely will have differences of opinion with all or part of this analysis. This analysis was not in any way prepared to contradict or supersede any other view. Both Quest Offshore and Blade Energy are providing this independent view expressly disclaiming any warranty, liability, or responsibility for completeness, accuracy, use, or fitness to any person for any reason.

7.1 General Comments

In general, it is understood that BSEE's Proposed Regulations are attempting to address upstream industry well design and operations perceived gaps or inadequacies. The industry continues to quickly address these topics on its own. Industry well technology is complex, taking time to engineer, develop, and apply for all stakeholders. Even small changes can result in significant ramifications, additional complexities, and costs immediately and in the future. This review strives to identify how BSEE's Proposed Rule will add immediate and future ramifications and added complexities to oil and gas operations on the continental shelf.

Considering the very complex nature of the Gulf of Mexico oil and gas industry, any single Proposed Rule change and the combination of all changes require evaluation by many stakeholders and technology providers.

BSEE's Proposed Rule is expected to have significant current and future effects on well engineering and operations. Industry's ongoing research and development on these topics is continuing, which includes new technologies being deployed currently and in the near to medium future. Much of industry's research and development efforts are focused on the challenges of deepwater drilling in the Gulf of Mexico water with a focus on life of the well, integrity and increasing resource development efficiencies. Research and development also continues in U.S. Government labs and U.S. Government funded projects with universities and others. The fruits of this R&D work will continue to be seen across industry now and beyond - and many are referenced herein. However, it is the opinion of this Report's authors that while some of these proposed regulations will lead to more industry research and development to overcome the burden imposed by these regulations; the prescriptive nature of the proposed rule will likely lead to some current and developing technologies being excluded from offshore oil and gas operations in the Gulf of Mexico.

This Report's authors believe it is positive for all stakeholders that BSEE references recognized developed standards (API, etc.) - as such references are accessible to all stakeholders - whether for U.S. application or globally. However, consideration must be taken as to the evolving nature of industry standards and this should be taken into consideration when writing existing or developing industry standards into proposed rules as this may preclude industry participants from adopting updated industry standards.

Additionally, BSEE needs to review the amount of time that industry and BSEE itself requires to staff and train sufficient numbers of competent personnel to monitor, review, and provide efficient approval feedback for many of these Proposed Rules. These include well designs and operations, resource development plans, real time monitoring, and 'BSEE approved verification organizations'. Additionally, the effects of the Proposed Rule requirements needs to be considered if proposed and existing rules are extended to all 'rig' types (including coiled tubing and wireline).

7.2 Analysis of the Proposed Rule

Under the main section: § 250.107 What must I do to protect health, safety, property, and the environment?

Proposed Rule: § 250.107 (a) Lists various compliance and documentation requirements and service fees.

Proposed Regulation Effect on Current Practices: Change will significantly impact well engineering and well operations by adding compliance time to document risk reducing efforts and well construction efforts.

Projected Operational Burden: For well planning, the change will impact well engineering by adding compliance time to document risk reducing efforts and well construction efforts. Including initially, significant compliance cost of around 2 months, including setting up to comply. Once compliance incorporated within a well operator's procedures, the burden should be no more than 2 man-days per individual well plan.

For well operations: The proposed rule adds to the rig management requirements. Initially, these effects could be significant, but once incorporated, the burden should be around 8 man-days per month of operation.

Projected Cost of Proposed Rule: The total cost for from 2017 to 2026 under the base development scenario developed for this report is projected at \$65.2 million, and an average annual cost \$6.5 million from 2017 to 2026.⁸

⁸ Cost estimates for each proposed rule subsection are provided based on projected activity levels prior to the adoption of the proposed rule (base case scenario, see Section 2 – Study Methodology for scenario development. Each cost estimate is provided as a 2017 to 2026 total and average annual additional cost to the Gulf Of Mexico OCS oil and natural gas industry as a whole.

Under the main section: § 250.107 What must I do to protect health, safety, property, and the environment?

Proposed Rule: § 250.107 (e) The BSEE may issue orders to ensure compliance with this part, including but not limited to, orders to produce and submit records and to inspect, repair, and or replace equipment. The BSEE may also issue orders to shut-in operations of a component or facility because of a threat of serious, irreparable, or immediate harm to health, safety, property, or the environment posed by those operations or because the operations violate law, including a regulation, order, or provision of a lease, plan, or permit.

Proposed Regulation Effect on Current Practices: Said "issued orders" seem to be targeted at operations.

Projected Operational Burden: None; unless the "issued orders" impose a compliance burden, expected to be around 8 man-days per month of operation per facility; or, if an operation is shut down, the burden could be extremely disruptive and costly to the operator.

Projected Cost of Proposed Rule: The total cost for from 2017 to 2026 under the base development scenario developed for this report is projected at \$61.7 million, and an average annual cost \$6.2 million from 2017 to 2026.

Under the main section: § 250.1703 What are the general requirements for decommissioning?

Proposed Rule: § 250.1703 (b) Permanently plug all wells. All packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198)

Proposed Regulation Effect on Current Practices: New requirement that all packers and bridge plugs would have to comply with API Spec. 11D1

Projected Operational Burden: The proposed rule would lead to the loss/scraping of inventory packers and bridge plugs which do not conform to API Spec. 11D1 manufactured prior to adoption of the rule. It is suggested that the rule adopts a grandfather clause for packers and bridge plugs manufactured prior to the adoption of the rule.

Projected Cost of Proposed Rule: The total cost of the effects of this rule are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules effect the loss/scraping of inventory packers and bridge plugs. See section 8.3, Other Cost Items – Packer and Bridge Plug Inventory Loss.

Under the main section: § 250.1703 What are the general requirements for decommissioning?

Proposed Rule: § 250.1703 (f) Follow all applicable requirements of subpart G; and;

Proposed Regulation Effect on Current Practices: Revised to add reference to the requirements of new Subpart G. This would make Subpart G applicable to decommissioning. The new regulations applying to "all drilling, completion, workover, and decommissioning operations..." The burden for the strict application of these regulations to decommissioning operations needs to be considered. These effects are difficult to estimate.

Projected Operational Burden: Well abandonments are normally considered as part of the plan only for exploration programs and not development programs. At the minimum the burden, applied to development wells, can be estimated at 3 man-days per individual employed in the operation who may be expected to operate the BOP plus 3 additional days of operating time plus services, needed to comply with the specified well control regulations.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.413 What must my description of well drilling design criteria address?

Proposed Rule: § 250.413 (g) A single plot containing curves for estimated pore pressures, formation fracture gradients, proposed drilling fluid weights, maximum equivalent circulating density, and casing setting depths in true vertical measurements;

Proposed Regulation Effect on Current Practices: This rule would require maximum ECD to the PP/FG/ MW & shoe plot. Additional engineering time will be required.

Projected Operational Burden: This rule would require operators to include fluid modeling and temperature to well planning. The burden should not exceed 4 man-days per individual well plan.

Projected Cost of Proposed Rule: The total cost for from 2017 to 2026 under the base development scenario developed for this report is projected at \$6.9 million, and an average annual cost \$690 thousand from 2017 to 2026.

Under the main section: § 250.414 What must my drilling prognosis include?

Proposed Rule: § 250.414 (c) Planned safe drilling margins between proposed drilling fluid weights and the estimated pore pressures, and proposed drilling fluid weights and the lesser of estimated fracture gradients or casing shoe pressure integrity test. Your safe drilling margins must meet the following conditions:

Proposed Regulation Effect on Current Practices: The safe drilling margins would also have to meet the following conditions (and was not previously defined): Static downhole mud weight must be greater than estimated pore pressure; Static downhole mud weight must be a minimum of one-half pound per gallon below the lesser of the casing shoe pressure integrity test or the lowest estimated fracture gradient; The ECD must be below the lesser of the casing shoe pressure integrity test or the lowest estimated fracture gradient; When determining the pore pressure and lowest estimated fracture gradient for a specific interval, related hole behavior must be considered (e.g., pressures, influx/loss of fluids, and fluid types).

The proposed changes seem to preclude the use of underbalanced drilling and managed pressure drilling by ignoring the use of applied surface pressure. This section defines mud as the only primary operational barrier allowable. It then goes further to require MW 0.5 ppg below FG and further require ECD to be below FG. This requires mud to be the primary barrier during drilling operations. Precluding the use of MPD, and drilling narrow margin PP/FG wells which is especially relevant in deepwater and ultra-deepwater wells, depleted reservoirs both on the shelf and in deepwater as well in areas with shallow hazards which require casing to be set at relatively shallow depths.

Projected Operational Burden: This proposed rule would likely have a very significant impact on Gulf of Mexico oil and gas activities. Today in the GOM, wells are being designed and operationally planned with BSEE review to use forms of Managed Pressure Drilling (MPD technologies). Globally, wells in shallow water, deepwater, and onshore are and have been drilled successfully using MPD technologies and methods. Existing and new deepwater rigs are being retrofitted or designed as 'MPD' ready rigs. The proposed rule may eliminate drilling narrow margin wells from being drilled. The proposed changes seem to preclude the use of underbalanced drilling and managed pressure drilling by ignoring the use of applied surface pressure. It also does not allow for alternate technologies to replace mud weight as the primary drilling barrier. There are many drilling technologies that allow for a barrier other than drilling fluid during operations. These technologies are employed both onshore and offshore throughout the world. If MPD and drilling with mud weights below .5 PPG is not allowed, many wells in the GOM could not be drilled. If these wells cannot be drilled & completed, then huge deepwater, depleted and other reserves will be undeveloped.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$10.7 billion, and an average annual cost \$1.1 billion from 2017 to 2026. This cost was calculated based on estimation of 30 percent of wells requiring additional casing strings, as well around 35 percent of wells lost due to this rule being abandoned while drilling.

Under the main section: § 250.414 What must my drilling prognosis include?

Proposed Rule: § 250.414 (j) The type of wellhead system and liner hanger system to be installed and a descriptive schematic, which includes but is not limited to pressure ratings, dimensions, valves, load shoulders, and locking mechanisms, if applicable; and

Proposed Regulation Effect on Current Practices: The rule would require operators to include wellhead and liner hanger specifications in the APD.

Projected Operational Burden: Additional information to be provided in the permitting process. The proposed additional requirement will add an engineering burden, estimated at 4-10 man-days per individual well plan regarding well design.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$6.9 million, an average annual cost from 2017 to 2026 of \$690 thousand.

Under the main section: § 250.414 What must my drilling prognosis include?

Proposed Rule: § 250.414 (k) Any additional information required by the District Manager.

Proposed Regulation Effect on Current Practices: New paragraph (k) would be added to require submittal of any additional information required by the District Manager. The proposed additional requirement could add a significant engineering burden.

Projected Operational Burden: Will allow for requests of additional information not specified in the CFR. The burden could be as minor as one rig-day per request or as severe as preventing the project from moving forward altogether. A provision for additional information is needed, but there must be a provision for justification (provided by BSEE) and a means for due process appeal (by the Operator). As currently written the rule essentially gives the District Supervisor the power to make requests without limit or justification.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario based on developed for this report is projected at \$1.2 billion, an average annual cost from 2017 to 2026 of \$113 million based on one request per well and one rig day per request.

Under the main section: § 250.415 What must my casing and cementing programs include?

Proposed Rule: § 250.415 (a) What must my casing and cementing programs include?

(a) The following well design information: (1) Hole sizes; (2) Bit depths (including measured and true vertical depth (TVD)); (3) Casing information including sizes, weights, grades, collapse and burst values, types of connection, and setting depths (measured and TVD) for all sections of each casing interval; and (4) Locations of any installed rupture disks (indicate if burst or collapse and rating);

Proposed Regulation Effect on Current Practices: The rule would require the rupture disc information for each casing string (if any).

Projected Operational Burden: The rule would require operators to modify drawings to this information include information, additional engineering time will be required. The burden should not exceed 15 man-days per individual well plan.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$25.9 million, an average annual cost from 2017 to 2027 of \$2.6 million.

Under the main section: § 250.418 What additional information must I submit with my APD?

Proposed Rule: § 250.418 (g) A request for approval if you plan to wash out or displace cement to facilitate casing removal upon well abandonment. Your request must include a description of how far below the mudline you propose to displace cement and how you will visually monitor returns;

Proposed Regulation Effect on Current Practices: The proposed rule would likely require a separate approval for well abandonment. The approval would require plan details included in the APD.

Projected Operational Burden: The proposed rule would likely require a more detailed well abandonment plans for casing removal. Additional engineering time will be required. The burden should not exceed 2 man-days per individual well plan.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$3.5 million, and an average annual cost of \$345 thousand from 2017 to 2026.

Under the main section: § 250.420 What well casing and cementing requirements must I meet?

Proposed Rule: § 250.420 (a) (6) Provide adequate centralization to ensure proper cementation; and

Proposed Regulation Effect on Current Practices: Include comments for centralizers and require "adequate centralization".

Projected Operational Burden: Additional time to run the required centralization, when centralizers may not have normally been run. Non Productive Time (NPT) associated with centralizer failures. Together, these can range from no additional time, to a likely estimate of one rig-day per individual well, to weeks of rig time plus services spent fishing centralizers and casing in the event of a catastrophic failure (unlikely). Additional engineering time will be required. The burden should not exceed 3 man-days per individual well plan. Would require documentation that the proposed centralizer program would provide adequate centralization (assumed to be 70% across and above production zones). Would have to attach and perhaps document and/or verify that centralizers are attached to casing.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$1.1 billion, an average annual cost \$113 million from 2017 to 2026 based on an average of one additional rig day per well drilled.

Under the main section: § 250.420 What well casing and cementing requirements must I meet?

Proposed Rule: § 250.420 (b)(4) If you need to substitute a different size, grade, or weight of casing than what was approved in your APD, you must contact the District Manager for approval prior to installing the casing.

Proposed Regulation Effect on Current Practices: Minor time requirement to report the needed change. Approval needed for changes to casing design.

Projected Operational Burden: A potential for delay while waiting on a decision from the District Manager. The delay should not exceed 3 rig-days per incident (a full weekend plus one day for review). The impact is expected not to exceed 1 man-day per incident. Changes require approval by District Manager. PE certification is required with submission.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$1.7 million, an average annual cost \$173 thousand from 2017 to 2026.

Under the main section: § 250.420 What well casing and cementing requirements must I meet?

Proposed Rule: § 250.420 (c)(2) You must use a weighted fluid to maintain an overbalanced hydrostatic pressure during the cement setting time, except when cementing casings or liners in riserless hole sections.

Proposed Regulation Effect on Current Practices: Would require the use of a weighted fluid to maintain an overbalanced hydrostatic pressure during the cement setting time, except when cementing casings or liners in riserless hole sections. Weighted spacers, designed to avoid going underbalanced during cement placement are a common practice offshore. If the intent is to provide enough hydrostatic pressure in the fluid, above the top of cement, to control the well without the pressure exerted by the cement column, then placement of this very heavy fluid column could be extraordinarily difficult, requiring a good deal of planning.

Projected Operational Burden: If the intent is to provide enough hydrostatic pressure in the fluid, above the top of cement, to control the well without the pressure exerted by the cement column, then placement of this very heavy fluid column could be extraordinarily difficult and prone to incurring Non Productive Time (NPT) due to lost circulation. Estimates range from no lost time to the loss of the hole section or entire well, in the event of a serious lost circulation event. An estimate of the additional planning for such a cement job is likely to range between 2 and 10 days per individual well. May affect the cementing operational design but wording in document only requires greater than seawater density of fluid to enhance well bore stability. Operator would have to do proper calculation to insure that this is followed. Would require review during certification process.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$983 million, an average annual cost \$98 million from 2017 to 2026 based on an average of six engineering days and one rig day per well.

Under the main section: § 250.421 What are the casing and cementing requirements by type of casing string?

Proposed Rule: § 250.421 (b) Conductor ... Design casing and select setting depths based on relevant engineering and geologic factors. These factors include the presence or absence of hydrocarbons, potential hazards, and water depths. Set casing immediately before drilling into formations known to contain oil or gas. If you encounter oil or gas or unexpected formation pressure before the planned casing point, you must set casing immediately and set it above the encountered zone. Use enough cement to fill the calculated annular space back to the mudline. Verify annular fill by observing cement returns. If you cannot observe cement returns, use additional cement to ensure fill-back to the mudline. For drilling on an artificial island or when using a well cellar, you must discuss the cement fill level with the District Manager

Proposed Regulation Effect on Current Practices: Revised to specify that if oil, gas, or unexpected formation pressure is encountered, the operator would have to set conductor casing immediately and set it above the encountered zone, even if it is before the planned casing point.

Projected Operational Burden: Change to well design and requires permitting and PE certification of design change. Time to secure the well bore and execute the contingency casing option may range between 2 and 7 days of rig time, depending on how much trouble is encountered. The engineering time required to provide a shallow contingency option would add an estimated 2 days to the well engineering process.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$440 million, an average annual cost \$44 million from 2017 to 2026 based on an assumption of ten percent of wells on average requiring four and a half rig days and two engineering days requiring execution of a contingency casing option after encountering unexpected formation pressure, oil, or gas.

Under the main section: § 250.427 What are the requirements for pressure integrity tests?

Proposed Rule: § 250.427 (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.

Proposed Regulation Effect on Current Practices: As was the case with § 250.414, the proposed changes seem to preclude the use of underbalanced drilling and managed pressure drilling by ignoring the use of applied surface pressure.

Projected Operational Burden: If MPD is not allowed, many wells in the GOM could not be drilled. Refer to comments for § 250.414 (c)

Projected Cost of Proposed Rule: Refer to comments for § 250.414 (c)

Under the main section: § 250.428 What must I do in certain cementing and casing situations?

Proposed Rule: § 250.428 (b) Need to change casing setting depths or hole interval drilling depth (for a BHA with an under-reamer, this means bit depth) more than 100 feet true vertical depth (TVD) from the approved APD due to conditions encountered during drilling operations. Submit those changes to the District Manager for approval and include a certification by a professional engineer (PE) that he or she reviewed and approved the proposed changes.

Proposed Regulation Effect on Current Practices: District Manager approval is now required if the casing setting depth change is more 100 feet regardless of whether it is deeper or shallower. Require

submission of a professional engineer (PE) certification, certifying that the PE reviewed and approved the proposed changes.

Projected Operational Burden: Statistically speaking, setting pipe shallower than planned is more common than deeper. As such, add an average of 1 day of rig time for waiting per individual well for this occurrence. An additional requirement for PE certification of the change has been added at an expected 3 man-days per well.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$195 million, an average annual cost \$19.5 million from 2017 to 2026 based on 20 percent of wells requiring a rig day and a 3 man days to receive approval to submit and receive approval to set casing more than 100 feet TVD from the approved APD.

Under the main section: § 250.428 What must I do in certain cementing and casing situations?

Proposed Rule: § 250.428 (c) Have indication of inadequate cement job (such as lost returns, no cement returns to mudline or expected height, cement channeling, or failure of equipment). (1) Locate the top of cement by: (i) Running a temperature survey; (ii) Running a cement evaluation log; or (iii) Using a combination of these techniques. (2) Determine if your cement job is inadequate. If your cement job is determined to be inadequate, refer to paragraph (d) of this section. (3) If your cement job is determined to be adequate, report the results to the District Manager in your submitted WAR.

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

Projected Operational Burden: The change may cause additional NPT due to the new definition for a failed cement job and that the NPT is expected to be disproportionately higher as depth increases. The estimated operational burden is 1 day of rig time per unit of depth squared (measured in thousands of feet) plus the cost of the investigative services. The estimated burden is 1 man-day per unit of depth squared (measured in thousands of feet). Operators would have the burden to review the multiple

potential causes for potential inadequate cement job, take action to try to evaluate potential problem, and then make recommendations for and take corrective action.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.428 What must I do in certain cementing and casing situations?

Proposed Rule: § 250.428 (k) Plan to use a valve on the drive pipe during cementing operations for the conductor casing, surface casing, or liner. Include a description of the plan in your APD. Your description must include a schematic of the valve and height above the water line. The valve must be remotely operated and full opening with visual observation while taking returns. The person in charge of observing returns must be in communication with the drill floor. You must record in your daily report and in the WAR if cement returns were observed. If cement returns are not observed, you must contact the District Manager and obtain approval of proposed plans to locate the top of cement before continuing with operations.

Proposed Regulation Effect on Current Practices: New § 250.428 (k) New requirement for the use of valves while cementing shallow strings. Add clarification concerning the use of valves on drive pipes during cementing operations for the conductor casing, surface casing, or liner, and require the following to assist BSEE in assessing the structural integrity of the well:

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

Projected Operational Burden: The engineering burden is expected to be 1 man-day per well to include the necessary details in the APD or APM.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$1.7 million, an average annual cost \$173 thousand from 2017 to 2026.

Under the main section: § 250.462 What are the source control and containment requirements?

Proposed Rule: § 250.462 What are the source control and containment requirements?

Proposed Regulation Effect on Current Practices: See below.

Projected Operational Burden: See below.

Projected Cost of Proposed Rule: This entry is used for containment system costs, membership, fees and other containment related items not itemized in the following containment related subsection subsections and excludes existing containment equipment. The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$1.2 billion, an average annual cost \$124 million from 2017 to 2026.

Under the main section: § 250.462 What are the source control and containment requirements?

Proposed Rule: § 250.462 (b) You must have access to and ability to deploy Source Control and Containment Equipment (SCCE) necessary to regain control of the well. SCCE means the capping stack, cap and flow system, containment dome, and/or other subsea and surface devices, equipment, and vessels whose collective purpose is to control a spill source and stop the flow of fluids into the environment or to contain fluids escaping into the environment. This equipment must include, but is not limited to, the following: (1) Subsea containment and capture equipment, including containment domes and capping stacks; (2) Subsea utility equipment, including hydraulic power, hydrate control, and dispersant injection equipment; (3) Riser systems; (4) Remotely operated vehicles (ROVs); (5) Capture vessels; (6) Support vessels; and (7) Storage facilities.

Proposed Regulation Effect on Current Practices: Requires operators to have access to and ability to deploy Source Control and Containment Equipment (SCCE) as above.

Projected Operational Burden: This is a very costly endeavor and will require a long term industry-wide effort to achieve. In the meantime, operators will need to survey the capabilities of the service community to develop a plan that satisfies the District Manager. Maintain contracts and maintain a fleet of equipment for emergency/ contingency use.

Projected Cost of Proposed Rule: See entry for § 250.462.

Under the main section: § 250.462 What are the source control and containment requirements?

Proposed Rule: § 250.462 (c) You must submit a description of your source control and containment capabilities to the Regional Supervisor and receive approval before BSEE will approve your APD, Form BSEE-0123. The description of your containment capabilities must contain the following: (1) Your source

control and containment capabilities for controlling and containing a blowout event at the seafloor, (2) A discussion of the determination required in paragraph (a) of this section, and (3) Information showing that you have access to and ability to deploy all equipment required by paragraph (b) of this section.

Proposed Regulation Effect on Current Practices: Requires submittal of a description of the source control and containment capabilities before BSEE would approve an APD. The submittal to the Regional Supervisor would need to include the following: The source control and containment capabilities for controlling and containing a blowout event at the seafloor, and a discussion of the determination required by paragraph (a), and information showing that the operator has access to, and the ability to deploy, all equipment necessary to regain control of the well.

Projected Operational Burden: Once the equipment and capability survey is complete to the satisfaction of the District Manager, then it should only add 1 man-day per individual well.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$1.1 million, an average annual cost \$110 thousand from 2017 to 2026.

Under the main section: § 250.462 What are the source control and containment requirements?

Proposed Rule: § 250.462 (d) You must contact the District Manager and Regional Supervisor for reevaluation of your source control and containment capabilities if your: (1) Well design changes, or (2) Approved source control and containment equipment is out of service.

Proposed Regulation Effect on Current Practices: District Manager and Regional Supervisor approval is now required for any well design changes or if any of the approved SCCE is out of service.

Projected Operational Burden: The potential for waiting on approval exists and is estimated at 1 rig-day per event. An engineering effort of 2 man-days per event is estimated.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$195 million, an average annual cost \$19.5 million from 2017 to 2026 based on 20 percent of wells facing one rig day and 2 man days of non-productive time while waiting on approval of the district manager due to well designs changes.

Under the main section: § 250.462 What are the source control and containment requirements?

Proposed Rule: § 250.462 (e) You must maintain, test, and inspect the source control and containment equipment identified in the following table according to these requirements: Equipment Requirements, you must: Additional information (1) Capping stacks (f) Function test all pressure holding critical components on a quarterly frequency (not to exceed 104 days between tests). Pressure holding critical

components are those components that will experience wellbore pressure during a shut-in after being functioned. (ii) Pressure test pressure holding critical components on a bi-annual basis, but not later than 210 days from the last pressure test. All pressure testing must be witnessed by BSEE and a BSEE-approved verification organization. Pressure holding critical components are those components that will experience wellbore pressure during a shut-in. These components include, but are not limited to: All blind rams, wellhead connectors, and outlet valves. (iii) Notify BSEE at least 21 days prior to commencing any pressure testing. (2) Production Safety Systems used for flow and capture operations. (f) Meet or exceed the requirements set forth in 30 CFR 50.800–250.808, Subpart H. (ii) Have all equipment unique to containment operations available for inspection at all times. (3) Subsea utility equipment Have all equipment unique to containment operations available for inspection at all times. Subsea utility equipment includes, but is not limited to: Hydraulic power sources, debris removal, hydrate control equipment, and dispersant injection equipment.

Proposed Regulation Effect on Current Practices: New inspection and testing requirements.

Projected Operational Burden: (1) Capping Stacks: Estimated at 80 man-days per year per system. (2) Prod. Safety Systems: Estimated at 80 man-days per year per system. (3) SS Utility equip.: No burden expected

Projected Cost of Proposed Rule: See entry for § 250.462.

Under the main section: § 250.518 Tubing and wellhead equipment

Proposed Rule: § 250.518 (New e) New paragraph (e) would add packer and bridge plug requirements including: Adherence to newly incorporated API Spec. 11D1, Packers and Bridge Plugs; Production packer setting depth t allow for a sufficient column of weighted fluid for hydrostatic control of the well; and Production packer setting depth criteria.

Proposed Regulation Effect on Current Practices: Completions fluids, including gas lifted wells, have clean brine in the A annulus. This rule will preclude gas lift completions because gas lift requires gas filling the A annulus above the operating gas lift valves. The rule should allow a phase-in application of API Spec. 11D1, so existing inventory of supplier and operator to be grandfathered and not rendered immediately scrap.

Projected Operational Burden: The rule should allow a phase-in application of API Spec. 11D1, so existing inventory of supplier and operator to be grandfathered and not rendered immediately scrap. The production tieback casing choices become limited or non-existent with the requirement for kill weight packer fluids hydrostatic control of the well in the A annulus or tubing annulus. Additionally, HPHT wells require very dense fluids to control the well. These fluids are very corrosive at high temperatures.

Projected Cost of Proposed Rule: The total cost of the effects of this rule are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules effect the loss/scraping of inventory packers and bridge plugs. See section 8.3, Other Cost Items – Packer and Bridge Plug Inventory Loss.

Under the main section: § 250.518 Tubing and wellhead equipment

Proposed Rule: § 250.518 (e)(2) During well completion operations, the production packer must be set at a depth that will allow for a column of weighted fluids to be placed above the packer that will exert a hydrostatic force greater than or equal to the force created by the reservoir pressure below the packer;

Proposed Regulation Effect on Current Practices: It may not be possible to set a packer deep enough to have a column of kill weight fluid at the packer.

Projected Operational Burden: If the casing design is suitable for the packer to casing loads, it should not matter if the casing is cemented or not. For those that aren't, additional engineering time will be required. The burden should not exceed 1 man-day per individual well plan.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$1.1 million, an average annual cost \$113 thousand. Although the effects of this rule under the proposed rule scenario were not calculated due to the time limitations associated with the study, in cases where it is not possible to set a packer deep enough to have a column of kill weight fluid at the packer the regulation as written would likely lead to the abandonment of otherwise safe and commercial wells.

Under the main section: § 250.518 Tubing and wellhead equipment

Proposed Rule: § 250.518 (e)(4) The production packer must be set at a depth that is within the cemented interval of the selected casing section.

Proposed Regulation Effect on Current Practices: Additional engineering time will be required. Sometimes it is not possible to get cement at the packer depth. For instance, where a production packer is set above a production liner top and the well is perforated inside the liner.

Projected Operational Burden: The burden should not exceed 1 man-day per individual well plan. In some cases a well could not completed due to this rule or if a block squeeze job is required to meet the proposed rule requirements.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$1.7 million, an average annual cost of \$173 thousand.

Note: The above costs exclude the costs which would be encountered if a well could not be completed due to this rule. These costs were unable to be calculated under the time limitations for this report but would be significantly larger than the calculated engineering costs if even minimal wells were required to be abandoned due to this rule.

Under the main section: § 250.518 Tubing and wellhead equipment

Proposed Rule: § 250.518 (New f) Would require, in your APM, a description and calculations of how the production packer setting depth was determined.

Proposed Regulation Effect on Current Practices: Operators would be required to calculate the hydrostatic head of a column of fluid to the packer.

Projected Operational Burden: Depending on wellbore dimensions this rule can make it impossible to complete a well that may otherwise be commercial. For those that aren't, additional engineering time will be required. The burden should not exceed 1 man-day per individual well plan. It is not uncommon to use a lower density packer fluid that does not exceed reservoir pressure hydrostatic.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$1.7 million, an average annual cost of \$173 thousand.

Note: The above costs exclude the costs which would be encountered if a well could not be completed due to this rule. These costs were unable to be calculated under the time limitations for this report but would be significantly larger than the calculated engineering costs if even minimal wells were required to be abandoned due to this rule.

Under the main section: § 250.619 Tubing and wellhead equipment

Proposed Rule: § 250.619 (f) Your APM must include a description and calculations for how you determined the production packer setting depth

Proposed Regulation Effect on Current Practices: See comments as § 250.518 (New f)

Projected Operational Burden: Depending on wellbore dimensions this rule can make it impossible to complete a well that may otherwise be commercial. For those that aren't, additional engineering time will be required. The burden should not exceed 1 man-day per individual well plan. It is not too uncommon to use a lower density packer fluid that does not exceed reservoir pressure hydrostatic. The additional engineering time should not exceed 1 man-day per individual APM.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$1.7 million, an average annual cost of \$173 thousand.

Under the main section: § 250.710 What instructions must be given to personnel engaged in well operations?

Proposed Rule: § 250.710 Prior to engaging in well operations, personnel must be instructed in: (a) Date and time of safety meetings. The safety requirements for the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment as required by subpart S of this part. Date and time of safety meetings must be recorded and available at the facility for review by BSEE representatives. (b) Well control. You must prepare a well-control plan for each well. Each well-control plan must contain instructions for personnel about the use of each well-control component of your BOP, procedures that describe how personnel will seal the wellbore and shear pipe before maximum anticipated surface pressure (MASP) conditions are exceeded, assignments for each crew member, and a schedule for completion of each assignment. You must keep a copy of your well-control plan on the rig at all times, and make it available to BSEE upon request. You must post a copy of the well-control plan on the rig floor.

Proposed Regulation Effect on Current Practices: Additional offshore drills will be required during well operations in critical hole sections (i.e., BHST > 300°F or MASP > 10,000 psi at the point of control or where H₂S or hydrocarbons are flowing at the surface).

Projected Operational Burden: The burden is estimated at one-half hour per rig-day of operation when applicable. The burden is estimated at 3 man-days per individual employed in the operation who may be expected to operate the BOP.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$2.3 billion, an average annual cost \$230 million based on one half a rig day per month of non-productive time and around 5 additional engineering days required to meet the increased training requirements.

Under the main section: § 250.712 What rig unit movements must I report?

Proposed Rule: § 250.712 What rig unit movements must I report?

Proposed Regulation Effect on Current Practices: This additional regulation will add the time needed to make the required application and it applies to all, but routine, well interventions, regardless of the type.

Projected Operational Burden: Wireline units are included in this regulation as a 'rig movement'. The burden could be estimated by surveying the service industry to get an idea of how many interventions are performed and multiply that number by 1 man-day of operator time plus the application fee, if applicable, needed to make the application. (Presently, Form BSEE-0144 is not listed in the fee

schedule but this study foresees that the increased burden on BSEE to process this additional information will require some cost.)

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.712 What rig unit movements must I report?

Proposed Rule: § 250.712 (a) You must report the movement of all rig units on and off locations to the District Manager using Form BSEE- 0144, Rig Movement Notification Report. Rig units include MODUs, platform rigs, snubbing units, wire-line units used for non-routine operations, and coiled tubing units. You must inform the District Manager 72 hours before: (1) The arrival of a rig unit on location; (2) The movement of a rig unit to another slot. For movements that will occur less than 72 hours after initially moving onto location (e.g., coiled tubing and batch operations), you may include your anticipated movement schedule on Form BSEE-0144; or (3) The departure of a rig unit from the location.

Proposed Regulation Effect on Current Practices: All equipment movement reported notification time from 24 hrs to 72 hrs. May submit permitting for short operations at the same time for move on/ move off.

Projected Operational Burden: This is cumbersome and expensive for wireline and coiled tubing units. Advance notice of wireline movements or coiled tubing movements could impose an operations burden on operators of these units depending on implementation.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.712: What rig unit movements must I report?

Proposed Rule: § 250.712 (e) If a drilling rig is entering OCS waters, you must inform the District Manager where the drilling rig is coming from.

Proposed Regulation Effect on Current Practices: Movement of rig prior to arriving in OCS waters.

Projected Operational Burden: Requires an update form based on change in equipment movement by more than 24 hours. This is not limited to rig movement but any equipment movement onto or off of a well.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.712 What rig unit movements must I report?

Proposed Rule: § 250.712 (f) If you change your anticipated date for initially moving on or off location by more than 24 hours, you must submit an updated Form BSEE-0144, Rig Movement Notification Report.

Proposed Regulation Effect on Current Practices: A new movement form required if the move on/ off location changes by more than 24 hours.

Projected Operational Burden: If reporting requirement leads to a movement delay, costs are increased.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.720 When and how must I secure a well?

Proposed Rule: § 250.720 When and how must I secure a well?

Proposed Regulation Effect on Current Practices: This is related to emergency or contingency operations. While the occurrence of compromised casing integrity can vary widely between operators and well types, a reasonable rate of occurrence for the purpose of this calculation is that one "critical" string in 50 can be expected to become compromised. (A critical string can be defined as one where the BHST > 300°F or MASP > 10,000 psi at the point of control or where H2S is flowing at the surface.)

Projected Operational Burden: While the mitigation efforts associated with a breach of casing integrity do vary widely, a reasonable estimate of the operational time required mitigate such a breach is 5 rig days per event. In these events, the time needed for the development of a mitigation strategy, then PE review and certification is estimated at 4 man-days per event. None, except for cases where prolonged operations have actually compromised well bore integrity.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.721 What are the requirements for pressure testing casing and liners?

Proposed Rule: § 250.721 (a): You must test each casing string that extends to the wellhead according to the following table...

Proposed Regulation Effect on Current Practices: Changes the requirements for pressure testing casing and liners, increase conductor test pressure from 200 psi to 250 psi., test surface, intermediate, and production to 70% of Minimum Internal Yield, test each drilling liner and liner lap before continuing

operations. Requires testing each production liner and liner lap, DM may approve or require additional casing test pressures. If a well would be fully cased and cemented, the operator would have to pressure test the well to the maximum anticipated shut-in tubing pressure before perforating the casing or liner. If a well would be an open-hole completion, the operator would have to pressure test the entire well to the maximum anticipated shut-in tubing pressure before drilling the open-hole section of the well. Requires for a PE certification of proposed plans to provide a proper seal if there is an unsatisfactory pressure test. Requires a negative pressure test on all wells that use a subsea BOP stack or wells with mudline suspension systems and outline the requirements for those tests.

Projected Operational Burden: Will require minor changes to pressure testing of BOPs. Presumably, the new requirement for District Manager notification in the event of an interruption of operations will be by telephone call. If a written notification must be made, assume 1/2 man-day per incident as the burden to the operator. Also requires time to pressure test. As well as possible safety risks associated with high pressure testing equipment at surface. Excess internal pressure causes tensile cracks and leak paths in the cement sheath. Inconsistent, and conflicting wording in this rule (requirement to test production casing to 70% test and testing maximum anticipated SITP).

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.721 What are the requirements for pressure testing casing and liners?

Proposed Rule: § 250.721. (e) If you plan to produce a well, you must: (1) For a well that is fully cased and cemented, pressure test the entire well to maximum anticipated shut-in tubing pressure before perforating the casing or liner; or (2) For an open-hole completion, pressure test the entire well to maximum anticipated shut-in tubing pressure before you drill the open-hole section.

Proposed Regulation Effect on Current Practices: Requires pressure testing the well to maximum anticipated shut in tubing pressure which is excessive.

Projected Operational Burden: Requires additional time to perform these tests is expected to be 1/2 rig-day of operating time per producing well to pressure test. There are risks associated with high surface pressure testing equipment.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$327 million, an average annual cost \$33 million based on one half a day of additional rig time for production wells.

Under the main section: § 250.721 What are the requirements for pressure testing casing and liners?

Proposed Rule: § 250.721 (f) You may not resume operations until you obtain a satisfactory pressure test. If the pressure declines more than 10 percent in a 30-minute test, or if there is another indication of a leak, you must submit to the District Manager for approval your proposed plans to replacement, repair the casing or liner, or run additional casing/liner to provide a proper seal. Your submittal must include a PE certification of your proposed plans.

Proposed Regulation Effect on Current Practices: PE certification of proposed plans to provide a proper seal if there is an unsatisfactory pressure test.

Projected Operational Burden: The estimated burden is one man-day per failed pressure test. A reasonable rate of occurrence for the purpose of this calculation is that one test in 40 can be expected to fail. The rig time spent waiting on orders following a failed pressure test, plus the time needed to mitigate and re-test are already being absorbed by the operator. The new requirement for certification is expected to add to this waiting time and is estimated at 1/2 rig-day per event.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$12.2 million, an average annual cost \$1.2 million based on one half a day of additional rig time for production wells.

Under the main section: § 250.721 What are the requirements for pressure testing casing and liners?

Proposed Rule: § 250.721 (g) You must perform a negative pressure test on all wells that use a subsea BOP stack or wells with mudline suspension systems.

Proposed Regulation Effect on Current Practices: Requires operators to perform a negative pressure test.

Projected Operational Burden: Additional rig time will be required during well operations to perform the tests. The burden is estimated at 0.5 rig-days per test.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$478 million, an average annual cost \$48 million.

Under the main section: § 250.722 What are the requirements for prolonged operations in a well?

Proposed Rule: § 250.722 What are the requirements for prolonged operations in a well? If wellbore operations continue within a casing or liner for more than 30 days from the previous pressure test of the well's casing or liner, you must:...

Proposed Regulation Effect on Current Practices: Requires operators to perform certain actions if wellbore operations continue within a casing or liner for more than 30 days from the previous pressure test of the well's casing or liner.

Projected Operational Burden: PE certification required if testing shows well below safety factors. Burden is estimated as 1 man-day.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$346 thousand, an average annual cost \$35 thousand.

Under the main section: § 250.723 What additional safety measures must I take when I conduct operations on a platform that has producing wells or has other hydrocarbon flow?

Proposed Rule: § 250.723 What additional safety measures must I take when I conduct operations on a platform that has producing wells or has other hydrocarbon flow? You must take the following safety measures when you conduct operations with a rig unit or lift boat on or jacked up over a platform with producing wells or that has other hydrocarbon flow:

Proposed Regulation Effect on Current Practices: Would require the installation of emergency shutdown stations on rig units tied into the production system.

Projected Operational Burden: This will take design and engineering time and new emergency shutdown procedure training for both the rig and platform crews.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.724 What are the real-time monitoring requirements??

Proposed Rule: § 250.724 What are the real-time monitoring requirements?

Proposed Regulation Effect on Current Practices: Presently, only a few of the super-major oil and gas operators have onshore real-time monitoring capability. Under these provisions, the rest of the operators would have to establish a monitoring facility and staff it 24/7, in order to comply. Requires a RTOC for monitoring BOPs, fluid handling and downhole conditions, requires onshore personnel to assist rig crew in monitoring, requires BSEE access upon request, and requires operators to notify DM if monitoring capability is lost.

Additionally, BSEE is considering extend this requirement beyond subsea BOPs, surface BOPs, floating facilities or BOPs operating in an HPHT environment

Projected Operational Burden: This will be a very costly addition to the regulations for most operators. Furthermore, the option for smaller operators to share a common monitoring facility is unlikely due to the sensitive nature of the data. Real Time Monitoring on all well operations, including shallow water shelf operations, will result in significant addition to the sensor, data integration, data telemetry band width, data reception and storage, and data monitoring & interpretation burden for all operators. There is significant uncertainty on the implementation and ongoing cost of these efforts due to the previously limited scale of these types of operations.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$670 million, an average annual cost \$67 million.

Under the main section: § 250.730 What are the general requirements for BOP systems and system components?

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

Proposed Regulation Effect on Current Practices: The proposed additions will serve to limit the number of vendors whose equipment can be used in operations under the regulation of BSEE. There will certainly be a cost associated with the increased consideration given to the design, testing and maintenance of the BOP and its associated systems.

Projected Operational Burden: This regulation should exclude components above the uppermost ram preventer (e.g., annular and LMRP or riser connect.) Annular preventer does not meet MASP, annulars are available up to 10,000 psi at this time and are not available for 15K, 20K or 25K stacks. Even with this change this may limit the number of contract rigs available to support operations in BSEE regulated waters. There will certainly be a cost associated with the increased consideration given to the operation and testing of the BOP and its associated systems while in service. There also exists the very real possibility that an operation will have to be suspended if a BOP fails to meet the standard and an alternative is not available.

Projected Cost of Proposed Rule: The total effects of this rule as written are impossible to calculate, as written this rule would preclude drilling wells with pressures greater than 10 thousand psi with available technology, these wells account for a significant portion of US OCS activity.

The total cost of the effects of this rule if modified are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules are expected to affect the replacement of BOPs for use in the US OCS. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.730 What are the general requirements for BOP systems and system components?

Proposed Rule: § 250.730 (a)(3) For surface and subsea BOPs, the pipe and variable bore rams installed in the BOP stack must be capable of effectively closing and sealing on the tubular body of any drill pipe, workstring, and tubing in the hole under MASP, as defined for the operation, with the proposed regulator settings of the BOP control system.

Proposed Regulation Effect on Current Practices: Would require that pipe and variable bore rams be capable of closing and sealing on drill pipe, workstrings, or tubing under MASP with the proposed regulator settings of the BOP control system.

Projected Operational Burden: The intent of this regulation is unclear. The BOP pressure test indicates if the BOP will seal for MASP or RWP as required. A shear test for on the actual run-in-hole tubing final completion tubing systems cannot be completed, because testing the final completion system will shear and destroy safety valve (SCSSV) and chemical injection or intelligent completion control lines and/or electrical submersible pump (ESP) or downhole sensor or intelligent completion electric cables. Nevertheless, these lines and/or cables are easy to shear (compared to the tubing), and a sample shop stump test tubing w/ lines-cables proves it all.

Projected Cost of Proposed Rule: The costs of this regulation have not been calculated as the shear tests as described in this regulation would be impossible to complete without damaging important well equipment and tubing effecting both the commercial viability and safety of a well. If the suggestion to allow performance of this testing at a test shop is enacted the effects will be minimal.

Under the main section: § 250.730 What are the general requirements for BOP systems and system components?

Proposed Rule: § 250.730 (a) (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.

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

Projected Operational Burden: This section seems to imply that the operator would specify, own and maintain BOP system. Also could lead to delays while waiting approval of new BOP schematics.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.730 What are the general requirements for BOP systems and system components?

Proposed Rule: § 250.730 (d) If you plan to use a BOP stack manufactured after the effective date of this regulation, you must use one manufactured pursuant to an API Spec. Q1 (as incorporated by reference in § 250.198) quality management system. Such quality management system must be certified by an entity that meets the requirements of ISO 17011.

Proposed Regulation Effect on Current Practices: Would require that if an operator plans to use a BOP stack manufactured after the effective date of the final rule, the operator must use one manufactured pursuant to API Spec. Q1.

Projected Operational Burden: Compliance effective date set in the Proposed Rule must allow industry time to engineer and design new API Spec. Q1 equipment - and allow time for existing inventory, work in process, and already ordered but not yet manufactured non Spec. Q1 equipment to be grandfathered and worked through.

Projected Cost of Proposed Rule: The total cost of the effects of this rule are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules are expected to affect the replacement of BOPs for use in the US OCS. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.731 What information must I submit for BOP systems and system components?

Proposed Rule: § 250.731 (a & b) A complete description of the BOP system and system components, (1) Pressure ratings of BOP equipment; (2) Proposed BOP test pressures (for subsea BOPs, include both surface and corresponding subsea pressures); (3) Rated capacities for liquid and gas for the fluid-gas separator system; (4) Control fluid volumes needed to close, seal, and open each component; You must submit: Including: (5) Control system pressure and regulator settings needed to achieve an effective seal of each ram BOP under MASP as defined for the operation; (6) Number and volume of accumulator bottles and bottle banks (for subsea BOP, include both surface and subsea bottles); (7) Accumulator pre-charge calculations (for subsea BOP, include both surface and subsea calculations); (8) All locking devices; and (9) Control fluid volume calculations for the accumulator system (for a subsea BOP system, include both the surface and subsea volumes). (b) Schematic drawings, (1) The inside diameter of the BOP stack, (2) Number and type of preventers (including blade type for shear ram(s)), (3) All locking

devices, (4) Size range for variable bore ram(s), (5) Size of fixed ram(s), (6) All control systems with all alarms and set points labeled, including pods, (7) Location and size of choke and kill lines (and gas bleed line(s) for subsea BOP), (8) Associated valves of the BOP system, (9) Control station locations, and (10) A cross-section of the riser for a subsea BOP system showing number, size, and labeling of all control, supply, choke, and kill lines down to the BOP.

Proposed Regulation Effect on Current Practices: What information must I submit for BOP systems and system components? The introductory text would reflect that the requirements of BOP description submittals would apply to APDs, APMs, and other required submittals. This introductory text would also clarify that if the operator is not required to resubmit the BOP information in subsequent applications, then the operator must document why the submittal is not required — in other words, the operator would need to reference the previously approved or accepted application or submittal and state that no changes have been made. New requirements for BOP description, new requirement for BOP drawings and labeling on drawings.

Projected Operational Burden: Testing required for BOP operation at specific water depth. An estimated 3 man-days per individual well to prepare the location-specific calculations for submittal.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$3.3 million, an average annual cost \$330 thousand.

Under the main section: § 250.731 What information must I submit for BOP systems and system components?

Proposed Rule: § 250.731 (c) Certification by a BSEE approved verification organization, Verification that: (1) Test data clearly demonstrates the shear ram(s) will shear the drill pipe at the water depth as required in § 250.732; (2) The BOP was designed, tested, and maintained to perform at the most extreme anticipated conditions; and (3) The accumulator system has sufficient fluid to function the BOP system without assistance from the charging system.

Proposed Regulation Effect on Current Practices: New requirement for BOP to shear at water depth, meets the extreme environment conditions and accumulator have sufficient fluid to function without assistance from the charging system.

Projected Operational Burden:

Changes to permitting documents. No indication in the Proposed Rule what a 'BSEE approved verification organization' may be or what is needed to qualify as one, or the current and future availability of sufficient verification organizations and personnel to properly staff these verification organizations at the effective date of the Proposed Rule and into the future.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study as well as the lack of available information on BSEE approved verification organizations. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Under the main section: § 250.731 What information must I submit for BOP systems and system components?

Proposed Rule: § 250.731 (d) Additional certification by a BSEE approved verification organization, if you use a subsea BOP, a BOP in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility, Verification that: (1) The BOP stack is designed for the specific equipment on the rig and for the specific well design; (2) The BOP stack has not been compromised or damaged from previous service; and (3) The BOP stack will operate in the conditions in which it will be used without assistance from the charging system.

Proposed Regulation Effect on Current Practices: New requirement for additional certification if an operator uses: a subsea BOP, a BOP in an HPHT environment, or a surface BOP on a floating facility. The certification would include verification of the following, the BOP stack is designed for the specific equipment on the rig and for the specific well design, the BOP stack has not been compromised or damaged from previous service; and the BOP stack will operate in the conditions in which it will be used.

Projected Operational Burden: In the short term, there may be limits to the number of qualifying and certifiable BOP systems available for service. BSEE does not want to limit the new requirements only to deepwater or HPHT wells. Additional certification is estimated at 3 man-days to accumulate the documentation plus 1 man-days for the actual certification. No indication in the Proposed Rule what a 'BSEE approved verification organization' may be or what is needed to qualify as one, or the current and future availability of sufficient verification organizations and personnel to properly staff these verification organizations at the effective date of the Proposed Rule and into the future.

Projected Cost of Proposed Rule: The expected documentation and verification cost of this proposed rule was not calculated due to the time limitations associated with this study as well as the lack of available information on BSEE approved verification organizations. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Other costs of the effects of this rule are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules are expected to affect the replacement of BOPs for use in the US OCS. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.731 What information must I submit for BOP systems and system components?

Proposed Rule: § 250.731 (e) If you are using a subsea BOP, descriptions of autoshear, deadman, and emergency disconnect sequence (EDS) systems, A listing of the functions with their sequences and timing.

Proposed Regulation Effect on Current Practices: This paragraph would require a listing of the functions with sequences and timing of autoshear, deadman, and emergency disconnect sequence (EDS) systems.

Projected Operational Burden: Additional information provided to the BSEE for BOP certification. Additional time will be required to prepare the documents for submission. The burden is estimated at 3 man-days per individual well.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$3.3 million, an average annual cost \$331 thousand.

Additionally: The BSEE is considering expanding the requirements of this paragraph to all BOPs. The BSEE is specifically soliciting comments on whether this certification requirement should be applied to all well operations, including shallow water shelf operations and operations with surface BOPs.

Proposed Regulation Effect on Current Practices: For some well operations (coiled tubing, and wireline specially) this will be an expensive new requirement. BSEE needs to review the amount of time that industry and BSEE itself requires to staff and train sufficient numbers of competent personnel to monitor, review, and provide efficient approval feedback for many of these Proposed Rules. These include well designs and operations, resource development plans, real time monitoring, and 'BSEE approved verification organizations'. Also, the effects of the Proposed Rule requirements need to consider the personnel necessary to cover BSEE's proposed extension to all 'rig' types (including coiled tubing and wireline), and to all shallow water and shelf operations.

Projected Operational Burden: BSEE needs to review the amount of time that industry and BSEE itself requires to staff and train sufficient numbers of competent personnel to monitor, review, and provide efficient approval feedback for many of these Proposed Rules. These include well designs and operations, resource development plans, real time monitoring, and 'BSEE approved verification organizations'. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Under the main section: § 250.731 What information must I submit for BOP systems and system components?

Proposed Rule: § 250.731 (f) Certification stating that the Mechanical Integrity Assessment Report required in § 250.732 (d) has been submitted within the past 12 months for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility.

Proposed Regulation Effect on Current Practices: Adds a certification requirement stating that the Mechanical Integrity Assessment Report required in proposed § 250.732 (d) has been submitted within the past 12 months for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility. The items covered under this section have not been routinely submitted to BSEE or obtained by the operators charged with responsibility to maintain well control.

Projected Operational Burden: 'BSEE approved verification organizations' required. Additionally life cycle monitoring of the BOP. This may be possible for new BOPs but difficult for existing BOPs with limited records of well life loads.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study as well as the lack of available information on BSEE approved verification organizations. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Under the main section: § 250.732 What are the BSEE approved verification organization requirements for BOP systems and system components?

Proposed Rule: § 250.732 General Overview

Proposed Regulation Effect on Current Practices: In reference to the third-party verification and documentation by a BSEE approved verification organization: The objective is to have this equipment monitored during its entire lifecycle by an independent third-party to verify compliance with BSEE requirements, OEM recommendations, and recognized engineering practices. The list of approved verification organizations would be limited to those that can clearly demonstrate the capability to perform this comprehensive detailed technical analysis.

Projected Operational Burden: BSEE has not yet established criteria of organizations and will need to maintain a list of approved suppliers.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$231 million, an average annual cost \$23 million based

on each operating rig requiring 30 man days per month of additional engineering time to comply with the sections requirements.

Under the main section: § 250.732 What are the BSEE approved verification organization requirements for BOP systems and system components?

Proposed Rule: § 250.732 (a) The BSEE will maintain a list of BSEE approved verification organizations that you may use. For an organization to become a BSEE approved verification organization, it must submit the following information to the Chief, Office of Regulatory Programs: Bureau of Safety and Environmental Enforcement: 45600 Woodland Road, Sterling, Virginia, 20166, for BSEE review and approval:

- 1) Previous experience in verification or in the design, fabrication, installation, repair, or major modification of BOPs and related systems and equipment;
- 2) Technical capabilities;
- 3) Size and type of organization;
- 4) In-house availability of, or access to, appropriate technology. This should include computer programs, hardware, and testing materials and equipment;
- 5) Ability to perform the verification functions for projects considering current commitments;
- 6) Previous experience with BSEE requirements and procedures; and
- 7) Any additional information that may be relevant to BSEE's review.

Proposed Regulation Effect on Current Practices: None, if companies can be grandfathered. Otherwise, there will be some time required to apply to be an approved verification company. BSEE will maintain a list of BSEE approved verification organizations, and also outline criteria to become a BSEE approved verification organization.

Projected Operational Burden: The effective date of new regulations requiring a BSEE approved verification organization is too short to have sufficient numbers or verification organizations available for all GOM OCS drilling well operations.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study as well as the lack of available information on BSEE approved verification organizations. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Under the main section: § 250.732 What are the BSEE approved verification organization requirements for BOP systems and system components?

Proposed Rule: § 250.732 (b) Prior to beginning any operation requiring the use of any BOP, you must submit verification by a BSEE approved verification organization and supporting documentation as required by this paragraph to the appropriate District Manager and Regional Supervisor. You must submit verification and documentation related to:

- 1) Shear Testing that:
 - i) Demonstrates that the BOP will shear the drill pipe and any electric-, wire-, and slick-line to be used in the well;
 - ii) Demonstrates the use of test protocols and analysis that represent recognized engineering practices for ensuring the repeatability and reproducibility of the tests, and that the testing was performed by a facility that meets generally accepted quality assurance standards;
 - iii) Provides a reasonable representation of field applications, taking into consideration the physical and mechanical properties of the drill pipe;
 - iv) Ensures testing was performed on the outermost edges of the shearing blades of the positioning mechanism as required in § 250.734(a)(16);
 - v) Demonstrates the shearing capacity of the BOP equipment to the physical and mechanical properties of the drill pipe; and
 - vi) Includes all testing results
- 2) Pressure integrity testing that:
 - i) Shows that testing is conducted immediately after the shearing tests;
 - ii) Demonstrates that the equipment will seal at the rated working pressure of the BOP for 30 minutes; and
 - iii) Includes all test results.
- 3) Calculations that
 - i) Include shearing and sealing pressures for all pipe to be used in the well including corrections for MASP

Proposed Regulation Effect on Current Practices: - This rule is applicable to any operation that requires any type of BOP, and would require verification of shear testing, pressure integrity testing, and calculations for shearing and sealing pressures for all pipe to be used. Each of these verifications must demonstrate the outlined specific requirements.

Projected Operational Burden: This requirement is vague related to HPHT environment and what existing standards are being exceeded. This indicates that the operator, not the equipment owner carries the burden for demonstrating reliability. Added time to perform a shear test is estimated at 20 man-days per ram plus an additional 5 man-days per size, weight & grade of pipe.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$45 million, an average annual cost \$4.5 million.

Under the main section: § 250.732 What are the BSEE approved verification organization requirements for BOP systems and system components?

Proposed Rule: § 250.732 (c) For wells in an HPHT environment, as defined by § 250.807(b), you must submit verification by a BSEE approved verification organization that the verification organization conducted a comprehensive review of the BOP system and related equipment you propose to use. You must provide the BSEE approved verification organization access to any facility associated with the BOP system or related equipment during the review process. You must submit the verifications required by this paragraph to the appropriate District Manager and Regional Supervisor before you begin any operations in an HPHT environment with the proposed equipment. The required submissions are:

- 1) Verification that the verification organization conducted a detailed review of the design package to ensure that all critical components and systems meet recognized engineering practices.
- 2) Verification that the designs of individual components and the overall system have been proven in a testing process that demonstrates the performance and reliability of the equipment in a manner that is repeatable and reproducible, including:
 - i) Identification of all reasonable potential modes of failure, and
 - ii) Evaluation of the design verification tests. The design verification tests must assess the equipment for the identified potential modes of failure.
- 3) Verification that the BOP equipment will perform as designed in the temperature, pressure, and environment that will be encountered, and
- 4) Verification that the fabrication, manufacture, and assembly of individual components and the overall system uses recognized engineering practices and quality control and assurance mechanisms.
 - i) 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.

Proposed Regulation Effect on Current Practices: This regulation would require a comprehensive review by a BSEE approved verification organization of BOP and related equipment being proposed for use in HPHT service. This would require a special verification process for BOP and related equipment being used in HPHT environments because the design conditions required for an HPHT environment exceed the limits of existing engineering standards. Additionally, the use of a BSEE approved verification body would provide BSEE with an additional layer of review and verification at all steps in the development process.

The paragraph makes it clear that the operator has the burden of clearly demonstrating the reliability of the equipment through a comprehensive review of the design, testing, and fabrication process.

Projected Operational Burden: This rule is related to § 250.731 (f), but explains what is required in the report. This will require added time to perform the additional verifications. The reviewer defers estimating this requirement to a BOP expert.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study as well as the lack of available information on BSEE approved verification organizations. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Under the main section: § 250.732 What are the BSEE approved verification organization requirements for BOP systems and system components?

Proposed Rule: § 250.732 (d) Once every 12 months, you must submit a Mechanical Integrity Assessment Report for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility. This report must be completed by a BSEE approved verification organization. You must submit this report to the Chief, Office of Regulatory Programs: Bureau of Safety and Environmental Enforcement: 45600 Woodland Road, Sterling, Virginia, 20166. This report must include:

- 1) A determination that the BOP stack and system meets or exceeds all BSEE regulatory requirements, industry standards incorporated into this subpart, and recognized engineering practices.
- 2) Verification that complete documentation of the equipment's service life exists that demonstrates that the BOP stack has not been compromised or damaged during previous service.
- 3) A description of all inspection, repair and maintenance records reviewed, and verification that all repairs, replacement parts, and maintenance meet regulatory requirements, recognized engineering practices, and OEM specifications.
- 4) A description of records reviewed related to any modifications to the equipment and verification that any such changes do not adversely affect the equipment's capability to perform as designed or invalidate test results.
- 5) A description of the Safety and Environmental Management Systems (SEMS) plans reviewed related to assurance of quality and mechanical integrity of critical equipment and verification that the plans are comprehensive and fully implemented.
- 6) Verification that the qualification and training of inspection, repair, and maintenance personnel for the BOP systems meet recognized engineering practices and OEM requirements.
- 7) A description of all records reviewed covering OEM safety alerts, all failure reports, and verification that any design or maintenance issues have been completely identified and corrected.
- 8) A comprehensive assessment of the overall system and verification that all components (including mechanical, hydraulic, electrical, and software) are compatible.

- 9) Verification that documentation exists concerning the traceability of the fabrication, repair, and maintenance of all critical components.
- 10) Verification of use of a formal maintenance tracking system to ensure that corrective maintenance and scheduled maintenance is implemented in a timely manner.
- 11) Identification of gaps or deficiencies related to inspection and maintenance procedures and documentation, documentation of any deferred maintenance, and verification of the completion of corrective action plans.
- 12) Verification that any inspection, maintenance, or repair work meets the manufacturer's design and material specifications.
- 13) Verification of written procedures for operating the BOP stack and LMRP (including proper techniques to prevent accidental disconnection of these components) and minimum knowledge requirements for personnel authorized to operate and maintain BOP components.
- 14) Recommendations, if any, for how to improve the fabrication, installation, operation, maintenance, inspection, and repair of the equipment.

Proposed Regulation Effect on Current Practices: The rule would include new requirements on the submission of a Mechanical Integrity Assessment Report on the BOP stack and systems. New paragraph (d) would outline the requirements for this report, which must be completed by a BSEE approved verification organization and submitted by the operator for operations that would require the use of a subsea BOP, a surface BOP on a floating facility, or a BOP that is being used in HPHT operations.

This rule specifically requires an annual submittal of a Mechanical Integrity Assessment Report for a subsea BOP, a BOP used in HPHT environment, or a surface BOP on a floating facility. This paragraph would outline the requirements of a Mechanical Integrity Assessment report.

Projected Operational Burden: This rule will result in added time to submit the annual assessment. The estimated time required to generate and submit the report is 3 man-days per stack per year.

Projected Cost of Proposed Rule⁹: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$1.3 million, an average annual cost \$130 thousand.

Under the main section: § 250.732 What are the BSEE approved verification organization requirements for BOP systems and system components?

Proposed Rule: § 250.732 (e) You must make all documentation that supports the requirements of this section available to BSEE upon request.

⁹ The projected cost of 250.732 (d) is based solely on the preparing of the verification reports, the cost associated with various inspections and procedures which are required to be verified are listed in the appropriate subsections. The removal or rewriting of those subsections without subsequent modification of the verification requirements could lead to significant increases in the projected cost of this subsection.

Proposed Regulation Effect on Current Practices: This rule will require operators to make all documentation that supports the requirements of this section available to BSEE upon request, and by extension, will require that a third party verify the testing and qualification of BOP equipment to ensure consistent results and provide a reasonable assurance of the performance of this equipment.

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

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

Projected Operational Burden: BSEE requested comments for the section (e) will take a longer than the current comment period to formulate.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study as well as the lack of available information on BSEE approved verification organizations. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Under the main section: § 250.733 What are the requirements for a surface BOP stack?

Proposed Rule: § 250.733 General Overview

Proposed Regulation Effect on Current Practices: This regulations would contain revisions clarifying its applicability to all operations covered under Subpart G. It also adds specific requirements for a surface BOP used in HPHT environments if operations are suspended to make repairs to any part of the BOP system.

The BSEE is requesting comments on requiring dual shear rams for BOPs used in HPHT environments, and how long it would take to comply with the dual shear requirement for BOPs used in HPHT environments."

Projected Operational Burden: Request for comments only.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study as well as the lack of available information on BSEE

approved verification organizations. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Under the main section: § 250.733 What are the requirements for a surface BOP stack?

Proposed Rule: § 250.733 (b) If you plan to use a surface BOP on a floating production facility you must:
(1) Follow the BOP requirements in § 250.734 (a)

- 1) You must comply with this requirement within 5 years from the publication of the final rule.
- 2) Use a dual bore riser configuration, for risers installed after the effective date of this rule, before drilling or operating in any hole section or interval where hydrocarbons are, or may be, exposed to the well. The dual bore riser must meet the design requirements of API RP 2RD (as incorporated by reference in § 250.198) including appropriate design for the most extreme anticipated operating and environmental conditions.
 - i) For a dual bore riser configuration, the annulus between the risers must be monitored during operations. You must describe in your APD or APM your annulus monitoring plan and how you will secure the well in the event a leak is detected.
 - ii) The inner riser for a dual riser configuration is subject to the requirements for testing the casing or liner at § 250.721.

Proposed Regulation Effect on Current Practices: This regulation would codify BSEE policy and would:

—Clarify that when using a surface BOP on a floating production facility:

- a) the same BOP requirements apply as in § 250.734 (a)(1), and
- b) a dual bore riser configuration would be required for risers installed after the effective date of this rule before drilling or operating in any hole section or interval where hydrocarbons may be exposed to the well;

—Require risers to meet the design requirements of API RP 2RD;

—Clarify that the annulus between the risers must be monitored during operations;

—Require a description of the monitoring plan in the APD or APM, including how you would secure the well if a leak is detected; and

—Clarify that the inner riser for a dual riser configuration is subject to the requirements for testing the casing or liner.

Additionally, API Standard 53 does not impose dual shear requirements for surface BOPs on floating facilities; however, this proposed rule would require dual shears.

Projected Operational Burden: The dual riser requirement may require additional engineering time going forward. Existing production floating facilities must have the room to accept dual bore risers or dual shear BOPs. If not, retrofitting may not be possible. This rule should allow existing and under construction units to be grandfathered in, otherwise the projected cost of the proposed rule would likely be much higher.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated in total, however, while some engineering and construction costs would be expected to design and manufacture new units to comply with these rules the effect on existing units would likely be orders of magnitude greater if a provision to grandfather in existing units is not inserted. As an example, newly installed or soon to be installed dry tree floating production units for some multi-billion dollar projects may be unable to drill and complete new wells if they could not be modified to meet the new requirement. This would likely lead to a 10 to 20 year reduction in the life of these fields and a loss of a majority of the investment into these projects.

Under the main section: § 250.733 What are the requirements for a surface BOP stack?

Proposed Rule: § 250.733 (e) You must install hydraulically operated locks.

Proposed Regulation Effect on Current Practices: This regulation would require the replacement of manual locks with hydraulically operated locks for surface BOPs.

Projected Operational Burden: Depending on the implementation timing of the requirement manufacturing, deliver, and installation of this equipment could lead to out of service time for drilling rigs with surface BOPs. Additionally, this requirement is unnecessary as manual locks on surface BOPs are always accessible.

Projected Cost of Proposed Rule: The projected cost of this rule under the base development scenario from 2017 to 2026 is \$5.5 million or \$550 thousand a year on average based on average replacement cost per surface BOP of around \$250 thousand.

Under the main section: § 250.733 What are the requirements for a surface BOP stack?

Proposed Rule: § 250.733 (f) For a surface BOP used in HPHT environments, if operations are suspended to make repairs to any part of the BOP system, you must stop operations at a safe downhole location. Before resuming operations you must:

- 1) Submit a revised APD or APM including documentation of the repairs and a certification from a BSEE approved verification organization stating that they reviewed the repairs, and that the BOP is fit for service; and
- 2) Receive approval from the District Manager.

Proposed Regulation Effect on Current Practices: The dual shear requirement could present an issue for rigs where stack space is already limited.

Projected Operational Burden: Repair conditions will impact operations, requiring the rig to stand by until the repairs are complete or a replacement stack can be acquired. In either event, an estimate of 5 to 10 rig-days seems appropriate, per failure that requires a repair.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a) (1) When operating with a subsea BOP system, you must have at least five remote-controlled, hydraulically operated BOPs. You must have at least one annular BOP, two BOPs equipped with pipe rams, and two BOPs equipped with shear rams. For the two shear ram requirement, you must comply with this requirement within 5 years from the publication of the final rule. Additionally:

- (i) Both BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, excluding the bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools.

Proposed Regulation Effect on Current Practices: The dual shear ram requirement is a very challenging requirement, with the need to be able to cut pipe and coiled tubing and wire while still being able to seal. If put into effect, it will

- Require operators to install a gas bleed line with two valves for the annular preventer.
- Necessitate that each annular has a gas bleed line if annulars were installed on both the LMRP and lower BOP stack
- Demand that the two valves would be able to hold pressure from both directions.
- Require a new device for centering drill pipe that is not one of the BOPs

Projected Operational Burden: The expected time needed to meet this requirement could be lengthy. The added requirements for accumulator capacity & redundancy, ROV intervention, emergency shut down, the use of acoustics, side outlet requirements, gas bleed capability below annulars, pipe positioning requirements, pipe compression mitigation and sub-sea battery monitoring will all contribute to significant amounts of engineering effort for new sub-sea BOP stacks.

Projected Cost of Proposed Rule: The total cost of the effects of this rule are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules are expected to affect the replacement of BOPs for use in the US OCS. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a)(1)(ii) The proposed rule requires that both shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that includes heavy-weight pipe or collars), workstring, tubing, appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric-, wire-, slick-line in the hole under MASP.

Proposed Regulation Effect on Current Practices: The proposed rule requires that both shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that includes heavy-weight pipe or collars), workstring, tubing, appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric-, wire-, slick-line in the hole under MASP.

Projected Operational Burden: The expected time needed to meet this requirement could be lengthy. Adoption of this requirement will require development of new rams that can shear tubing, wireline, etc.

Projected Cost of Proposed Rule: The total cost of the effects of this rule are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules are expected to affect the replacement of BOPs for use in the US OCS. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a)(3) When operating with a subsea BOP system, you must have the accumulator capacity located subsea, to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface. Additionally, the accumulator capacity must:

- (i) Function each required shear ram, choke and kill side outlet valves, one pipe ram, and disconnect the LMRP.
- (ii) Have the capability of delivering fluid to each ROV function i.e., flying leads.
- (iii) Have dedicated independent bottles for the autoshear, deadman, and EDS systems.
- (iv) Perform under MASP conditions as defined for the operation

Proposed Regulation Effect on Current Practices: Generally conforms with API 53.

Projected Operational Burden: Minor modifications to hydraulic system and accumulators.

Projected Cost of Proposed Rule: The estimated cost of modifying BOPs is around \$150 thousand per BOP, this cost is excluded from the cumulative analysis to prevent double counting. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a)(4) When operating with a subsea BOP system, you must have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention capability. Additionally, the ROV must be capable of performing critical functions, including opening and closing each shear ram, choke and kill side outlet valves, all pipe rams, and LMRP disconnect under MASP conditions as defined for the operation. The ROV panels on the BOP and LMRP must be compliant with API RP 17H (as incorporated by reference in § 250.198).

Proposed Regulation Effect on Current Practices: The proposed rule will increase potential leak paths by requiring an increased requirement for ROV stabs and require minor modification of existing BOP units.

Projected Operational Burden: As written the rule will lead to increased maintenance costs and time, as well as increasing the difficulty of other BOP maintenance. Will also require modifications to existing BOPs including addition of high flow stabs and valves.

Projected Cost of Proposed Rule: The estimated cost of modifying existing BOPs is around \$350 thousand per BOP, this cost is excluded from the cumulative analysis to prevent double counting. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a)(5) When operating with a subsea BOP system, you must maintain an ROV and have a trained ROV crew on each rig unit on a continuous basis once BOP deployment has

been initiated from the rig until recovered to the surface. The crew must examine all ROV related well-control equipment (both surface and subsea) to ensure that it is properly maintained and capable of shutting in the well during emergency operations. Additionally, the crew must be trained in the operation of the ROV. The training must include simulator training on stabbing into an ROV intervention panel on a subsea BOP stack. The ROV crew must be in communication with designated rig personnel who are knowledgeable about the BOP's capabilities.

Proposed Regulation Effect on Current Practices: This rule will require communication between the ROV crew and the rig personnel familiar with the BOP.

Projected Operational Burden: Will require additional training and ROV operations.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.734: What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a)(6) When operating with a subsea BOP system, you must provide autoshear, deadman, and EDS systems for dynamically positioned rigs; provide autoshear and deadman systems for moored rigs. Additionally, in reference to the above rule:

- (i) Autoshear system means a safety system that is designed to automatically shut-in the wellbore in the event of a disconnect of the LMRP. This is considered a rapid discharge system.
- (ii) Deadman system means a safety system that is designed to automatically shut-in the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods. This is considered a rapid discharge system.
- (iii) Emergency Disconnect Sequence (EDS) system means a safety system that is designed to be manually activated to shut-in the wellbore and disconnect the LMRP in the event of an emergency situation. This is considered a rapid discharge system.
- (iv) Each emergency function must close at a minimum, two shear rams in sequence and be capable of performing their expected shearing and sealing action under MASP conditions as defined for the operation.
- (v) Your sequencing must allow a sufficient delay for closing the upper shear ram after beginning closure of the lower shear ram to provide for maximum shearing efficiency.
- (vi) The control system for the emergency functions must be a fail-safe design, and the logic must provide for the subsequent step to be independent from the previous step having to be completed.

Proposed Regulation Effect on Current Practices: This paragraph would require each emergency function to include both shear rams closing under MASP. The sequencing of each emergency function

would have to provide for the lower shear ram beginning closure before the upper shear ram would begin closure. The control system for the emergency functions would be required to be a failsafe design, and each step in the logic would have to be independent of the previous step being completed.

Projected Operational Burden: Will require modifications to the control systems of BOP. For safety reasons emergency disconnect sequences must disconnect in the shortest possible time, the sequencing of the shear rams will delay disconnect.

Projected Cost of Proposed Rule: Although the cost effects of this rule are not included in the total estimated cost of the rule to prevent double counting the addition of timing circuits is estimated at \$100 thousand per BOP excluding additional hydraulic tubing and engineering which will be dependent on the specific design of a BOP.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a)(15) When operating with a subsea BOP system, you must install a gas bleed line with two valves for the annular preventer with the following requirements:

- (i) The valves must hold pressure from both directions;
- (ii) If you have dual annulars, where one annular is on the LMRP and one annular is on the lower BOP stack, you must install a gas bleed line on each annular

Proposed Regulation Effect on Current Practices: The proposed rule requires operators to install a gas bleed line with two valves for the second annular preventer if one is in the LMRP and one in the lower BOP stack.

Projected Operational Burden: This regulation would lead to a significant requirement to modify the stack framework and to purchase suitable annular BOPs to allow the installation of a lower gas bleed line. Immediate implementation of this rule would likely lead to a significant slowdown in drilling from rigs with subsea BOPs due to the time required to manufacture and install components that comply with this rule.

Projected Cost of Proposed Rule: Although the cost effects of this rule are not included in the total estimated cost of the rule to prevent double counting the addition suitable annular is estimated at \$2 million per BOP.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a)(16) When operating with a subsea BOP system, you must use a BOP system that has the following mechanisms and capabilities:

- (i) A mechanism coupled with each shear ram to position the entire pipe, including connection, completely within the area of the shearing blade and ensure shearing will occur any time the shear rams are activated. This mechanism cannot be another ram BOP or annular preventer, but you may use those during a planned shear. You must install this mechanism within 7 years from the publication of the final rule;
- (ii) The ability to mitigate compression of the pipe stub between the shearing rams when both shear rams are closed;
- (iii) If your control pods contain a subsea electronic module with batteries, a mechanism for personnel on the rig to monitor the state of charge of the subsea electronic module batteries in the BOP control pods.

Proposed Regulation Effect on Current Practices: This regulation requires the installation of a vertical positioning system to position the entire pipe within in the shearing blade. These positioning systems are currently not available. The requirement will also require the installation of a position indicator for each ram BOP, wellhead connector, and LMRP connector that is viewable by the ROV. This would require sensing and displaying pressure within the BOP that is viewable by the ROV.

Projected Operational Burden: Addition of positioning system will likely require significant modification of BOPs, the extent of which is difficult to ascertain prior to the development of these systems. Additional costs associated with modification of control systems are likely.

Projected Cost of Proposed Rule: The total cost of the effects of this rule are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules are expected to affect the replacement of BOPs for use in the US OCS. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (b) If operations are suspended to make repairs to any part of the subsea BOP system, you must stop operations at a safe downhole location. Before resuming operations you must:

1. Submit a revised permit with a verification report from a BSEE approved verification organization documenting the repairs and that the BOP is fit for service;
2. Perform a new BOP test in accordance with § 250.737 and § 250.738 upon relatch including deadman and ROV intervention; and
3. Receive approval from the District Manager.

Proposed Regulation Effect on Current Practices: Require that if operations are suspended to make repairs to the BOP, operations would have to be stopped at a safe downhole location, submit a revised

permit with a report from a BSEE approved verification organization documenting the repairs and that the BOP is fit for service, perform a new BOP test upon relatch and receive approval from the District Manager.

Projected Operational Burden: This rule would require a minimum of 1 rig day to report and get permission to continue operations.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$48 million, an average annual cost \$4.7 million based on five percent of wells requiring submission of the required information and waiting on approval.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (c) If you plan to drill a new well with a subsea BOP, you do not need to submit with your APD the verifications required by this subpart for the open water drilling operation. Before drilling out the surface casing, you must submit for approval a revised APD, including the verifications required in this subpart.

Proposed Regulation Effect on Current Practices: Additions to this section would provide that if an operator plans to drill a new well with a subsea BOP, the operator does not need to submit with its APD the verifications required by this subpart for the open water drilling operation. However, before drilling out the surface casing, the operator would be required to submit for approval a revised APD, including the third-party verifications required in this subpart.

Projected Operational Burden: This rule would require a minimum of one (1) man-day to report and get permission to continue operations.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$3.3 million, an average annual cost \$330,000.

Under the main section: § 250.735 What associated systems and related equipment must all BOP systems include?

Proposed Rule: § 250.735 (a) A BOP system must include a surface accumulator system that provides 1.5 times the volume of fluid capacity necessary to close and hold closed all BOP components against MASP. The system must operate under MASP conditions as defined for the operation. You must be able to operate all BOP functions without assistance from a charging system, with the blind shear ram being the last in the sequence, and still have enough pressure to shear pipe and seal the well with a minimum

pressure of 200 psi remaining on the bottles above the precharge pressure. If you supply the accumulator regulators by rig air and do not have a secondary source of pneumatic supply, you must equip the regulators with manual overrides or other devices to ensure capability of hydraulic operations if rig air is lost.

Proposed Regulation Effect on Current Practices: This rule clarifies that the requirements are for a surface accumulator system, that the system would have to operate all BOP functions, including shearing pipe and sealing the well against MASP without assistance from a charging system; and that these provisions would apply to all BOP systems, not just surface BOP stacks.

Projected Operational Burden: This would require additional tanks, accumulators and pumps to be installed on affected drilling rigs. The ease of the addition of this equipment will be highly affected by the availability of usable deck space in appropriate areas on a given drilling rig.

Projected Cost of Proposed Rule: Cost is estimated at a minimum of \$500 thousand per drilling rig if no major structural modification are needed. If major structural modifications are needed costs would be expected to be significantly higher. Due to the time limits associated with this study the costs excluding possible modifications to rig structures under the base development scenario are projected at \$48 million total from 2017 to 2026, an annual average of around \$4.8 million.

Under the main section: § 250.737 What are the BOP system testing requirements?

Proposed Rule: § 250.737 (d) Additional test requirements. You must meet the following additional BOP testing requirements: [§ 250.737 (d)(1)-(12)]

Proposed Regulation Effect on Current Practices: This list of additional rules will lead to new ROV requirements which will mean an extra effort for the ROV service provider until the fleet is wholly compatible. The expanded function testing requirements for the auto-shear, deadman and EDS will add considerable time to the APD & APM submittal effort for subsea operations.

Projected Operational Burden: The reviewer has deferred an estimate for this effort to the ROV service provider, but the expanded function testing requirements for the auto-shear, deadman and EDS are expected to add 0.5 rig-days to the sub-surface BOP test procedures.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$237 million, an average annual cost \$23.7 million.

Under the main section: § 250.737 What are the BOP system testing requirements?

Proposed Rule: § 250.737 (d)(5) You must alternate tests between control stations and pods. Additionally:

- i) For two complete BOP control stations:
 - a) You must designate a primary and secondary station, and both stations must be function-tested weekly.
 - b) The control station used for the pressure test must be alternated between pressure tests, and
 - c) For a subsea BOP, the pods must be rotated between control stations during weekly function testing, and the pod used for pressure testing must be alternated between pressure tests.
- ii) Any additional control stations must be function tested every 14 days.

Proposed Regulation Effect on Current Practices: This rule expands testing requirements for two BOP control stations. The operator would be required to designate the control stations as primary and secondary and function-test each station weekly. The control station used to perform the pressure test would be required to be alternated between each pressure test. For a subsea BOP, the operator would be required to rotate the pods between each control station during the weekly function tests and alternate the pod used for pressure testing between each pressure test. If additional control stations are installed, they would have to be tested every 14 days.

Projected Operational Burden: This rule requires at least 15 min per function test for each additional control station. If additional control stations (beyond the minimum of two) are installed, they would have to be tested every 14 days.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was included in the parent level cost of rule § 250.737 (d) to avoid double counting.

Under the main section: § 250.737 What are the BOP system testing requirements?

Proposed Rule: § 250.737 (d)(12) You must test and verify closure capability of all ROV intervention functions on your subsea BOP. In addition:

- (i) Each ROV must be fully compatible with the BOP stack ROV intervention panels.
- (ii) You must submit test procedures, including how you will test each ROV intervention function, with your APD or APM for District Manager approval.
- (iii) You must document all your test results and make them available to BSEE upon request.

Proposed Regulation Effect on Current Practices: These new provisions include requirements that:

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

Projected Operational Burden: These regulations will require additional documentation which will take 15 minutes of engineer time per ROV testing.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was included in the parent level cost of rule § 250.737 (d) to avoid double counting.

Under the main section: § 250.737 What are the BOP system testing requirements?

Proposed Rule: § 250.737 (d)(13) You must function test the autoshear, deadman, and EDS systems separately on your subsea BOP stack during the stump test. The District Manager may require additional testing of the emergency systems. You must also test the deadman system and verify closure of the shearing rams during the initial test on the seafloor. Additionally:

- (i) You must submit test procedures with your APD or APM for District Manager approval. The procedures for these function tests must include the schematics of the actual controls and circuitry of the system that will be used during an actual autoshear or deadman event.
- (ii) The procedures must also include the actions and sequence of events that take place on the approved schematics of the BOP control system and describe specifically how the ROV will be utilized during this operation.
- (iii) When you conduct the initial deadman system test on the seafloor, you must ensure the well is secure and, if hydrocarbons have been present, appropriate barriers are in place to isolate hydrocarbons from the wellhead. You must also have an ROV on bottom during the test.
- (iv) The testing of the deadman system on the seafloor must indicate the discharge pressure of the subsea accumulator system throughout the test.
- (v) For the function test of the deadman system during the initial test on the seafloor, you must have the ability to quickly disconnect the LMRP should the rig experience a loss of station-keeping event. You must include your quick-disconnect procedures with your deadman test procedures.

Proposed Regulation Effect on Current Practices: The test procedures must be submitted for District Manager approval and the proposed rule would require that the procedures include:

- Schematics of the circuitry of the system that would be used during an autoshear or deadman event;

—The approved schematics of the BOP control system with the actions and sequence of events that would take place; and

—How the ROV would be used during the well-control operations.

During the initial test of the deadman system, the operator would need to have the ability to quickly disconnect the LMRP. The operators would also have to submit the quick-disconnect procedures with the deadman test procedures in the APD or APM. The operator would have to include in its procedure a description of how it plans to verify closure of a casing shear ram if installed. All test results would have to be documented and submitted to BSEE upon request.

Projected Operational Burden: If the rule allows simulated testing of the deadman switch the operational burden is expected to be minimal.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the unclear intent of the proposed rule as noted above.

Under the main section: § 250.738 What must I do in certain situations involving BOP equipment or systems?

Proposed Rule: § 250.738 (b) If you need to repair, replace, or reconfigure a surface or subsea BOP system; (1) First place the well in a safe, controlled condition as approved by the District Manager (e.g., before drilling out a casing shoe or after setting a cement plug, bridge plug, or a packer). (2) Any repair or replacement parts must be manufactured under a quality assurance program and must meet or exceed the performance of the original part produced by the OEM. (3) You must receive approval from the District Manager prior to resuming operations with the new, repaired, or reconfigured BOP. You must submit a report from a BSEE approved verification organization to the District Manager certifying that the BOP is fit for service.

Proposed Regulation Effect on Current Practices: This regulation requires that the operator receive approval from the District Manager prior to resuming operations after replacing, repairing, or reconfiguring the BOP system. To obtain approval, the operator would have to submit a report from a BSEE approved verification organization attesting that the BOP system is fit for service. Any repair or replacement parts would have to be manufactured under a quality assurance program and would have to meet or exceed the performance of the original part produced by the OEM.

Projected Operational Burden: The expected rig down-time associated with the BOP repairs should be fully captured under § 250.733 (f).

Projected Cost of Proposed Rule: Not currently calculated [See § 250.733(f)]

Under the main section: § 250.738 What must I do in certain situations involving BOP equipment or systems?

Proposed Rule: § 250.738 (j) If you encounter a situation where the need to remove the BOP stack arises, you must have a minimum of two barriers in place prior to BOP removal. You must obtain approval from the District Manager of the two barriers prior to removal and the District Manager may require additional barriers.

Proposed Regulation Effect on Current Practices: This regulation will require that, after pipe or casing is sheared either intentionally or unintentionally, the operator would have to retrieve, inspect, and test the BOP as well as submit a report to the District Manager from a BSEE approved verification body, stating that the BOP is fit to return to service. Additionally, the subsea stack must be pulled and inspected by a BSEE approved verification company who then must submit a report stating that the BOP is fit to be returned to service following any shearing event. The report should be able to be prepared while the stack is being re-run, assuming the inspection was satisfactory.

Projected Operational Burden: None, as the rig time associated with pulling, inspecting, re-running and testing the sub-surface BOP stack is already a requirement.

Projected Cost of Proposed Rule: Due to the lack of expected operational burdens, there has not been an associated cost calculated for this regulation.

Under the main section: § 250.738: What must I do in certain situations involving BOP equipment or systems?

Proposed Rule: § 250.738 (o) If 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), you must comply with all testing, maintenance, and inspection requirements in this subpart that are applicable to those well-control components. If any redundant component fails a test, you must submit a report from a BSEE approved verification organization that describes the failure, and confirms that there is no impact on the BOP that will make it unfit for well-control purposes. You must submit this report to the District Manager and receive approval before resuming operations. The District Manager may require additional information.

Proposed Regulation Effect on Current Practices: This rule adds new requirements applicable to redundant well-control components in BOP systems that are in addition to components required in Subpart G. If any redundant component fails a test, you must submit a report from a BSEE approved verification organization that describes the failure and confirms that there is no impact on the BOP that will make it unfit for well-control purposes.

Projected Operational Burden: The associated time burden of waiting on approval following the failure of a redundant BOP system is estimated at 1 rig-day per event. Failure of a redundant component will require a report to be submitted to the District Manager, estimated to be one man-day's effort per failed BOP test.

Projected Cost of Proposed Rule: The total cost for from 2017 to 2026 under the base development scenario developed for this report is projected at \$48 million, an average annual cost \$4.8 million based on five percent of wells encountering a failure of a redundant BOP system.

Under the main section: § 250.738 What must I do in certain situations involving BOP equipment or systems?

Proposed Rule: § 250.738 (p) If you need to position the bottom hole assembly, including heavy-weight pipe or collars, and bottom-hole tools across the BOP for tripping or any other operations, you must ensure that the well has been stable for a minimum of 30 minutes prior to positioning the bottom hole assembly across the BOP. You must have, as part of your well-control plan required by § 250.710, procedures that enable the immediate removal of the bottom hole assembly from across the BOP in the event of a well control or emergency situation (for dynamically positioned rigs, your plan must also include steps for when the EDS must be activated) before MASP conditions are reached as defined for the operation.

Proposed Regulation Effect on Current Practices: This rule will result in new requirements that operators would have to meet if they need to position the bottom hole assembly across the BOP for tripping or any other operations, including:

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

—Including in the well-control plan (required by proposed § 250.710(b)) procedures for immediately removing the bottom hole assembly from across the BOP in the event of a well control or emergency situation before exceeding MASP conditions.

Projected Operational Burden: If this situation arises, the rig must wait at least 30 minutes to prove well stability.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.739 What are the BOP maintenance and inspection requirements?

Proposed Rule: § 250.739 (b) A complete breakdown and detailed physical inspection of the BOP and every associated system and component must be performed every 5 years. This complete breakdown and inspection may not be performed in phased intervals. A BSEE approved verification organization is required to be present during the inspection and must compile a detailed report documenting the inspection, including descriptions of any problems and how they were corrected. You must make this report available to BSEE upon request.

Proposed Regulation Effect on Current Practices: This new requirement details the procedures for a complete breakdown and inspection of the BOP and every associated component (which is undefined) which rig owners would be required to undertake every 5 years. This paragraph would also clarify that the complete breakdown and inspection may not be performed in phased intervals. BSEE approved verification organization would have to be present documenting the inspection and any problems encountered and produce a detailed report. The requirement for a complete tear-down & inspection every five years will require considerable manpower on the part of the manufacturer and the BSEE approved verification organization.

Projected Operational Burden: The rig time required to swap BOP stacks is estimated at 80 rig-days every five years, plus the cost to remove tear-down, rebuilt, retest, and reinspect the BOP. This would be based on rig owners purchasing additional rig specific BOPs prior to the five year inspection which can then be reused to reduce downtime. Additional burdens associated with this rule are likely due to the limited infrastructure associated with this type of inspection including a lack of shore based OEM facilities, cranes to remove BOPs at US shipyards, and appropriate testing equipment.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$8.9 billion, an average annual cost \$895 million. This is cost is based on \$40 million per additional BOP as a one off cost, and \$15 million of inspection and yard costs and 80 days of downtime every five years for each active rig utilizing a subsea BOP.

Under the main section: § 250.743 What are the well activity reporting requirements?

Proposed Rule: § 250.743 (c) The Well Activity Report (WAR) must include a description of the operations conducted, any abnormal or significant events that affect the permitted operation each day within the report from the time you begin operations to the time you end operations, any verbal approval received, the well's as-built drawings, casing, fluid weights, shoe tests, test pressures at surface conditions, and any other information required by the District Manager. For casing cementing operations, indicate type of returns (i.e., full, partial, or none). If partial or no returns are observed, you must indicate how you determined the top of cement. For each report, indicate the operation status for the well at the end of the reporting period. On the final WAR, indicate the status of the well (completed, temporarily abandoned, permanently abandoned, or drilling suspended) and the date you finished such operations.

Proposed Regulation Effect on Current Practices: This regulation will require a report describing the operations conducted, any abnormal or significant events that affect the permitted operation, verbal approvals, the wells as-built drawings, casing fluid weights, shoe tests, test pressures at surface conditions, and status of the well at the end of the reporting period. The final WAR would include the date operations finished.

Projected Operational Burden: Properly completing these forms is estimated to require two hours of time from each engineer working on each well.

Projected Cost of Proposed Rule: The total cost for the studied period under the base development scenario developed for this report is projected at \$443 thousand, an average annual cost \$43 thousand.

Under the main section: § 250.746 What are the recordkeeping requirements for casing, liner, and BOP tests, and inspections of BOP systems and marine risers?

Proposed Rule: 250.746 (e) Requires that the company identify on the daily report any problems or irregularities observed during BOP system testing and record actions taken to remedy the problems or irregularities. Any leaks associated with the BOP or control system during testing are considered problems or irregularities and must be reported immediately to the District Manager, and documented in the WAR. If any problems or irregularities are observed during testing, operations must be suspended until the District Manager determines that you may continue.

Proposed Regulation Effect on Current Practices: Clarifies that any irregularity that is identified during BOP system testing must be identified on the daily report, any leaks observed during testing or observed from the control station are considered irregularities and would have to be reported to BSEE. Operations would have to be suspended until BSEE grants approval to continue after irregularities.

Projected Operational Burden: One rig day per irregularity of any type, though possibly longer if irregularities are serious. Some irregularities are very minor and should not have to be reported or await approval to continue.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at \$123.8 million, an average annual cost \$12.4 million based on the assumption that ten percent of wells on average may encounter an irregularity requiring one day of non-productive time while waiting on the district manager.

7.3 Other Cost Items

Packer and Bridge Plug Inventory Loss

The following regulations [§ 250.1703 (b), § 250.518 (New e)] are expected to lead to a loss of already manufactured and held in inventory packers and bridge plugs that fail to meet the specifications required by the new rule. The cost of this inventory was calculated by estimating the number of packers and bridge plugs required on a per well basis and under the assumption that one and a half years' worth of inventory is held by various suppliers and operators. The introduction of a grandfathering provision for

packers and bridge plugs manufacturer prior to the adoption of this rule would remove this expected cost of the proposed rule. The total cost for replacement of inventory packers and bridge plugs under the base development scenario developed for this report is projected at \$32 million, an average annual cost \$3.2 million.

BOP Replacement

The following regulations [§ 250.730, § 250.730 (d), § 250.734 (a)(1), § 250.734 (a)(1)(ii), § 250.734 (a)(3), § 250.734 (a)(4), § 250.734 (a)(6), § 250.734 (a)(15), § 250.734 (a)(16)] are expected to lead to the replacement of subsea blow out preventers in the US OCS. The accumulation of these regulations is projected to lead to the inability to economically modify existing subsea blow out preventers for use in the US OCS, leading to the replacement of these BOPs. Any modification costs listed above are solely for indicative purposes in the event of a limited adoption of the proposed rule as written and are not included in the cumulative costs in this study. The total projected cost of replacing subsea BOPs for use in the Gulf of Mexico OCS is projected at around \$2.1 billion from 2017 to 2026 and annual average of around \$210 million over the same period.

BSEE Approved Verification Organizations

BSEE Approved Verification Organizations (BAVO) are not defined by the regulations [§ 250.731 (c), § 250.731 (d), § 250.732 (a), § 250.732 (c), § 250.732 (e), § 250.733] and do not currently exist as proposed by the rule. As such it is not possible to calculate the cost that the involvement of these organizations will entail or the possible effects that delays in defining and approving these organizations may impose.

Section 8 - Extended Methodology Appendix

8.1 General Methodology

Quest's methodology focused on constructing a tiered "bottom-up" model that separated the complete life cycle of offshore operations and subsequent effects into four main categories – these categories are further developed into cases and presented as the Base Development scenario and Proposed Rule scenario within the paper. The four main categories are as follows;

- A "Rule" model that independently assesses the individual or combined effects of the proposed rules within "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control"
- An "Activity Forecast" model assessing Quest's project database and project modeling information under which the number of expected projects is developed
- A "Spending" model based on the requirements of developing projects within the "Activity Forecast"
- An "Economic" model focusing on the economic impact on employment and government revenue from the "Spending" model.

Three (Activity Forecast, Spending, and Economic models) of the four individual subsections were further split into five additional criteria that create an individual "Project" model. These categories include; seismic, leasing activity, drilling, infrastructure & project development, and production & operation. (Table 12)

Table 12: Oil and Gas Project Development Model – Aspects of Additional Criteria Included by Model

	Activity Forecast	Spending Model	Economic Model
Seismic	<ul style="list-style-type: none"> • Pre-Lease Seismic • Leased Block Seismic • Shoot Type 	<ul style="list-style-type: none"> • Cost per acre 	<ul style="list-style-type: none"> • Economic Activity due to seismic spending within states
Leasing	<ul style="list-style-type: none"> • Yearly lease sales for individual regions 	<ul style="list-style-type: none"> • Bonus bid prices • Rental rate 	<ul style="list-style-type: none"> • Federal and state revenues created through lease sales • Economic activity due to increased state/personal spending
Drilling	<ul style="list-style-type: none"> • Number of wells drilled • Water depth of wells drilled • Number of drilling rigs required 	<ul style="list-style-type: none"> • Cost per well 	<ul style="list-style-type: none"> • Economic activity due to activity within states
Project Development & Operation	<ul style="list-style-type: none"> • Project size • Project development time 	<ul style="list-style-type: none"> • Spending per project • Per project spending timeline 	<ul style="list-style-type: none"> • Division of state spending • Economic activity due to project development within states vicinity
Production	<ul style="list-style-type: none"> • Production type and amount 	<ul style="list-style-type: none"> • Oil and gas price forecast 	<ul style="list-style-type: none"> • Federal and state revenues created by royalty sharing • Economic activity due to increased states/personal spending

Source: Quest Offshore Resources, Inc.

In order to estimate the economic effects and project activity losses through the "Project" model, additional analysis was undertaken to understand which projects would be disrupted through the inability to discover and develop the reserves. This was presented through additional analysis of the Base Development scenario and is provided as the Proposed Rule scenario.

8.2 Rule Costing Methodology

The analysis of spending related to proposed "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control" was undertaken through the individual analysis of each rule, while also considering the accretive effects of multiple rules placed upon similar equipment, tasks, and future opportunities. The cost of the proposed rule changes were analyzed on either the basis of time required to complete each activity or the replacement cost of equipment where applicable. Equipment costs were calculated using actual or estimated replacement costs depending on the availability of information. All costs are attempted to be calculated on the basis of the most economic reasonable method to overcome the burden imposed by the regulation. General assumptions used within the modeling are as followed:

- Engineering rate (daily) : \$923¹⁰
- Drilling rate (daily) including spread costs¹¹: \$800 thousand for deepwater drilling, \$250 thousand for shallow water drilling.

The determination of any further costs incurred through the loss of productivity within the region was undertaken through the application of the calculated costs and burdens of rules onto Quest's project and well forecast developed for this study from Quest's proprietary databases. The total cost of the rule was calculated through the combination of reanalyzing Quest's "Project", "Activity", "Spending", and "Economic" forecasts with the additional cost of the rule changes. The difference between the two cases, from a spending, economic, and regulatory perspective provide the total estimated "cost" of the rule.

8.3 Project Development Methodology

In order to account for both currently active projects within the Gulf of Mexico and longer-term prospects that will be developed towards the end of the forecast period into the study's project development activity, Quest incorporated two models into the project development forecast. The near-term activity was developed on known projects or prospects currently under consideration for development, while a longer term forecast was developed on top of the near-term forecast through the analysis of oil prices, leasing trends, development trends, historic project sizes and other relevant factors

The forecast of near term projects utilized Quest's Gulf of Mexico project database that encompasses all major portions of offshore field development (e.g. exploration, number of wells, length of pipelines, size of FPS unit, installation vessels, etc.). In addition to that information, lead times for project development, sanctioning trends and additional spending information led to the expected timeline

¹⁰ Based on the most recent Society of Petroleum Engineers Salary Survey and estimates of total compensation costs.

¹¹ Based on current day rate and spread (additional drilling) costs from Quest Offshore Data.

and development costs of individual projects. The summation of these costs and timelines over all of the forecasted individual projects provided the total cost of near term projects.

Longer term projects were developed under a less independent methodology for individual projects. In the place of the project-specific spending model, Quest applied historical and current trends within the region to future developments (e.g. a greater focus on deep water oil projects as well as infield drilling and subsea infrastructure) in order to apply the proper costs and timelines to the expected activity. Projects were still delineated by individual timelines and the development scenarios that may be expected of future activity within the region, but were calculated using assumptions on industry trends in production methods instead of on confirmed aspects of the specific projects.

With regards to the Proposed Rule scenario, projects were examined for potential hurdles that would be encountered under the new regulations through several criteria identified from Quest and Blade's research. These topics were focused on emerging trends such as HPHT reservoirs, ultra-deep wells, projects developing already depleted reservoirs, as well as increased project costs. These identified factors drove the forecasted possibility of delays or lost activity due to project economics, technology-driven hurdles, or regulatory impasses. Furthermore, where necessary, additional costs were administered to subsections of projects where increased costs were to be expected for calculations in the economic model.

8.4 Project Spending Methodology

This spending analysis accounts for all capital investment and operational spending through the entire "life cycle" of operations. Every offshore oil or natural gas project must go through a series of steps in order to be developed. Initial expenditures necessary to identify targets and estimate the potential recoverable resources in place include seismic surveys (G&G) and the drilling and evaluation of exploration & appraisal (E&A) wells. For projects that are commercially viable, the full range of above-surface and below-water (subsea) equipment must be designed and purchased. Offshore equipment includes production platforms and on-site processing facilities, as well as below-water equipment generally referred to as SURF (Subsea, Umbilicals, Risers and Flowlines). Finally, the equipment must be installed and additional development wells must be drilled. Once under production, further operational expenditures (OPEX) are required to perform ongoing maintenance, production operations and other life extension activities as necessary for continued field production and optimization.

Spending for individual projects was subdivided into sixteen categories covering the complete life cycle of a single offshore project, as well as two additional groups for natural gas processing and operation. Timing and cost for individual categories were assigned based on the previously mentioned project types where prices are scaled according to the complexity and size of the project. (Table 13)

Table 13: Oil and Gas Project Spending Model

	Activity Model	Spending Model	Economic Model
Seismic (G&G)	<ul style="list-style-type: none"> Number of leases 2D vs. 3D 	<ul style="list-style-type: none"> Cost per acre 	<ul style="list-style-type: none"> Operation requirements
SURF	<ul style="list-style-type: none"> Trees, manifolds, and other subsea equipment Umbilicals Pipelines, flowlines, and risers 	<ul style="list-style-type: none"> Cost per item Cost per mile 	<ul style="list-style-type: none"> Fabrication locations
Platforms	<ul style="list-style-type: none"> Fixed Platforms Floating Production System 	<ul style="list-style-type: none"> Unit size 	<ul style="list-style-type: none"> Fabrication locations
Installation	<ul style="list-style-type: none"> Surf Installation Platform Installation 	<ul style="list-style-type: none"> Number of vessels Type of vessels Vessel dayrate 	<ul style="list-style-type: none"> Operation requirements Shorebase locations
Drilling	<ul style="list-style-type: none"> Exploration drilling Development drilling 	<ul style="list-style-type: none"> Rig type Rig dayrate 	<ul style="list-style-type: none"> Operating requirements Shorebase locations
Engineering	<ul style="list-style-type: none"> FEED 	<ul style="list-style-type: none"> CAPEX OPEX 	<ul style="list-style-type: none"> Technological centers
Operating Expenditures (OPEX)	<ul style="list-style-type: none"> Supply and personnel requirements Project maintenance Project reconfiguration 	<ul style="list-style-type: none"> Type of project and associated infrastructure 	<ul style="list-style-type: none"> Shorebase locations

Source: Quest Offshore Resources, Inc.

Upon compiling the scenario of overall spending estimates, Quest deconstructed the "local content" of oil and gas operations within the studied region. Individual tasks were analyzed on a component-by-component basis to provide an estimate of the percentage of regional, national, and international construction required by offshore operations. Additionally, delineations were made at the regional level in order to project spending for individual states. Considerations were based on current oil and gas development, the proximity to reserves and production, strategic locations such as shore bases and ports, as well as Bureau of Economic Analysis (BEA) data pertaining to each state's present economic distribution.

8.5 Economic Methodology

The study's GDP and job data were calculated using the BEA's RIMs II Model providing an input-output multiplier on spending at the industry and state levels for each defined category. Model outputs considered from spending effects include number of jobs and GDP multiplier effects. Further delineation is presented in the form of direct and indirect and induced job numbers, which encompass the number of jobs relating to the spending in that category versus indirect and induced jobs that are created from pass-through spending. For states considered within the study that contained no RIMs II multipliers for specific sectors, state multiplier from economies that most closely paralleled those in question were replicated.

Rims Categories used:

- Architectural, Engineering, and Related Services
- Construction
- Drilling Oil and Gas Wells
- Fabricated Metal Product Manufacturing

- Mining and Oil and Gas Field Machinery Manufacturing
- Oil and Gas Extraction
- Steel Product Manufacturing from Purchased Steel
- Support Activities for Oil and Gas Operations

8.6 Governmental Revenue Development

Governmental revenue data is presented in three categories; bonus bids from lease sales, rents from purchased but not yet developed leases, and royalty payments from producing leases. The projected revenue was calculated under the assumption that the current operating structure of the Gulf of Mexico would remain in place where applicable. Lease sales and rental rates were calculated through the simulation of yearly lease sales within each individual area, while the number of leases acquired was modeled on oil price forecasts, historical rates, and on the estimated amount of reserves in the western and central OCS regions.

The federal / state government revenue split of leases, rents and royalties were modeled under the application of GOMESA (Gulf of Mexico Energy Security Act). As Quest understands the rule and phase II beginning in 2017, GOMESA regulations would effectively split 37.5 percent of OCS bonus bid, rent, and royalty income between the appropriate states. GOMESA has an annual revenue cap of \$500 million for the Gulf States.

Production pricing were calculated using the EIA estimates for both West Texas Intermediate (WTI) spot and Henry Hub natural gas prices¹². Additional governmental revenues such as income and corporate taxes were considered outside of the scope of this study, and are likely to provide additional government revenues throughout the studied period.

¹² United States. Energy Information Administration. *Annual Energy Outlook 2015*. Energy Information Administration, 14 April 2015.

Section 9 – Additional Tables Appendix

Table 14: Annual Compliance Costs by Affected Activity or Equipment – Proposed Rule Scenario (\$Millions)

Category	2017	2018	2019	2020	2021	2022	2023
BOP Replacement or Modification	\$922	\$856	\$1,246	\$1,223	\$1,184	\$1,225	\$1,163
Compliance and Documentation	\$9	\$11	\$10	\$10	\$11	\$10	\$10
Containment	\$112	\$113	\$177	\$177	\$186	\$93	\$82
Rig Requirements	\$175	\$186	\$181	\$185	\$186	\$176	\$171
Real Time Monitoring (RTM)	\$69	\$69	\$71	\$63	\$55	\$50	\$46
Tubing and Wellhead Equipment	\$33	\$0	\$1	\$1	\$1	\$0	\$0
Well Design	\$1,441	\$1,205	\$1,312	\$1,395	\$1,380	\$1,387	\$1,243
Grand Total	\$2,661	\$2,441	\$2,997	\$3,055	\$3,003	\$2,931	\$2,715

Category	2024	2025	2026	2027	2028	2029	2030
BOP Replacement or Modification	\$712	\$752	\$823	\$918	\$1,038	\$914	\$851
Compliance and Documentation	\$10	\$9	\$12	\$11	\$13	\$12	\$14
Containment	\$82	\$83	\$83	\$74	\$77	\$78	\$79
Rig Requirements	\$171	\$171	\$191	\$205	\$225	\$224	\$225
Real Time Monitoring (RTM)	\$47	\$48	\$47	\$40	\$54	\$83	\$61
Tubing and Wellhead Equipment	\$0	\$0	\$1	\$1	\$1	\$1	\$1
Well Design	\$1,112	\$1,253	\$1,427	\$1,547	\$1,741	\$1,901	\$1,943
Grand Total	\$2,135	\$2,317	\$2,584	\$2,795	\$3,148	\$3,212	\$3,175

Source: Quest Offshore Resources, Inc.

Table 15: Annual Compliance Costs by Affected Activity or Equipment – Base Development Scenario (\$Millions)

Category	2017	2018	2019	2020	2021	2022	2023
BOP Replacement or Modification	\$925	\$926	\$1,336	\$1,331	\$1,373	\$1,465	\$1,419
Compliance and Documentation	\$11	\$12	\$11	\$12	\$13	\$13	\$14
Containment	\$113	\$114	\$179	\$181	\$190	\$99	\$97
Rig Requirements	\$204	\$205	\$205	\$215	\$239	\$239	\$240
Real Time Monitoring (RTM)	\$74	\$72	\$73	\$85	\$83	\$52	\$56
Tubing and Wellhead Equipment	\$33	\$1	\$1	\$1	\$1	\$1	\$1
Well Design	\$1,062	\$1,470	\$1,597	\$1,721	\$1,691	\$1,739	\$1,551
Grand Total	\$2,421	\$2,800	\$3,402	\$3,547	\$3,589	\$3,606	\$3,378

Category	2024	2025	2026	2027	2028	2029	2030
BOP Replacement or Modification	\$978	\$1,041	\$1,052	\$1,133	\$1,233	\$1,120	\$1,047
Compliance and Documentation	\$13	\$12	\$15	\$15	\$14	\$15	\$16
Containment	\$98	\$85	\$86	\$76	\$80	\$139	\$146
Rig Requirements	\$244	\$247	\$250	\$259	\$272	\$273	\$274
Real Time Monitoring (RTM)	\$63	\$63	\$50	\$66	\$59	\$95	\$92
Tubing and Wellhead Equipment	\$1	\$1	\$1	\$1	\$1	\$1	\$1
Well Design	\$1,357	\$1,601	\$1,830	\$1,981	\$2,186	\$2,470	\$2,382
Grand Total	\$2,753	\$3,050	\$3,284	\$3,531	\$3,845	\$4,113	\$3,957

Source: Quest Offshore Resources, Inc.

Table 16: US Gulf of Mexico Production by Type – Proposed Rule Scenario (Thousands)¹³

Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Oil - BOE/D	1,563	1,338	1,292	1,275	1,411	1,499	1,634	1,693	1,724	1,745	1,760
Gas - BOE/D	1,119	909	765	662	634	548	550	541	544	555	574
Total	2,682	2,248	2,056	1,937	2,045	2,047	2,183	2,234	2,268	2,299	2,334

Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Oil - BOE/D	1,758	1,742	1,730	1,718	1,712	1,717	1,730	1,733	1,740	1,748
Gas - BOE/D	593	613	635	656	683	718	760	796	834	876
Total	2,351	2,355	2,364	2,374	2,396	2,435	2,490	2,529	2,573	2,623

Source: Quest Offshore Resources, Inc.

Table 17: US Gulf of Mexico Production by Type – Base Development Scenario (Thousands)

Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Oil - BOE/D	1,563	1,338	1,292	1,275	1,411	1,499	1,634	1,722	1,799	1,833	1,874
Gas - BOE/D	1,119	909	765	662	634	548	550	558	583	602	634
Total	2,682	2,248	2,056	1,937	2,045	2,047	2,183	2,280	2,381	2,435	2,508

Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Oil - BOE/D	1,916	1,920	1,938	1,944	1,969	1,990	2,018	2,035	2,044	2,051
Gas - BOE/D	674	704	742	774	817	863	915	963	1,006	1,052
Total	2,590	2,624	2,679	2,718	2,787	2,852	2,933	2,999	3,050	3,104

Source: Quest Offshore Resources, Inc.

Table 18: Government Revenues by Source – Proposed Rule Scenario (\$Millions)

Revenue Source	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rent	\$238	\$218	\$218	\$236	\$232	\$182	\$217	\$236	\$237	\$241	\$263
Bids	\$920	\$325	\$1,815	\$1,299	\$976	\$707	\$1,041	\$1,041	\$1,051	\$1,039	\$1,161
Royalties	\$5,203	\$5,635	\$5,481	\$5,684	\$5,870	\$4,288	\$5,755	\$6,112	\$6,245	\$6,466	\$6,685
Total	\$6,361	\$6,177	\$7,515	\$7,219	\$7,079	\$5,177	\$7,013	\$7,389	\$7,533	\$7,746	\$8,110

Revenue Source	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rent	\$263	\$291	\$294	\$290	\$306	\$333	\$331	\$338	\$350	\$370
Bids	\$1,135	\$1,249	\$1,252	\$1,231	\$1,286	\$1,389	\$1,373	\$1,392	\$1,432	\$1,502
Royalties	\$6,869	\$7,017	\$7,195	\$7,368	\$7,573	\$7,859	\$8,160	\$8,418	\$8,706	\$8,996
Total	\$8,267	\$8,557	\$8,740	\$8,889	\$9,164	\$9,580	\$9,865	\$10,148	\$10,488	\$10,870

Source: Quest Offshore Resources, Inc.

¹³ 2010 to 2014 Production is actual production.

Table 19: Government Revenues by Source – Base Development Scenario (\$Millions)

Revenue Source	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rent	\$238	\$218	\$218	\$236	\$232	\$182	\$217	\$245	\$261	\$247	\$281
Bids	\$920	\$325	\$1,815	\$1,299	\$976	\$707	\$1,041	\$1,084	\$1,158	\$1,067	\$1,237
Royalties	\$5,203	\$5,635	\$5,481	\$5,684	\$5,870	\$4,288	\$5,755	\$6,296	\$6,631	\$6,948	\$7,311
Total	\$6,361	\$6,177	\$7,515	\$7,219	\$7,079	\$5,177	\$7,013	\$7,625	\$8,050	\$8,262	\$8,828

Revenue Source	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rent	\$275	\$285	\$298	\$305	\$342	\$322	\$337	\$341	\$373	\$391
Bids	\$1,188	\$1,222	\$1,270	\$1,294	\$1,437	\$1,344	\$1,397	\$1,404	\$1,525	\$1,590
Royalties	\$7,725	\$8,012	\$8,385	\$8,708	\$9,130	\$9,582	\$10,046	\$10,477	\$10,879	\$11,273
Total	\$9,188	\$9,518	\$9,953	\$10,307	\$10,909	\$11,247	\$11,780	\$12,222	\$12,777	\$13,254

Source: Quest Offshore Resources, Inc.

Table 20: Project Development Spending by Component – Proposed Rule Scenario (\$Millions)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Drilling	\$6,069	\$6,270	\$8,188	\$7,610	\$9,411	\$7,862	\$8,069	\$8,547	\$9,611	\$10,611	\$10,404
Engineering	\$2,098	\$2,517	\$2,206	\$2,022	\$1,940	\$1,297	\$2,463	\$3,065	\$2,981	\$2,632	\$2,622
G&G	\$183	\$163	\$348	\$368	\$439	\$319	\$372	\$321	\$305	\$354	\$383
Install	\$1,918	\$631	\$762	\$2,791	\$2,995	\$1,442	\$1,084	\$837	\$1,152	\$1,401	\$1,377
OPEX	\$19,533	\$19,466	\$18,920	\$18,355	\$17,836	\$17,845	\$17,766	\$17,629	\$17,052	\$16,791	\$16,351
Platforms	\$3,215	\$4,150	\$3,620	\$2,715	\$2,530	\$1,700	\$2,960	\$1,717	\$2,105	\$2,025	\$1,922
SURF	\$2,098	\$2,513	\$2,051	\$1,613	\$1,503	\$1,144	\$2,213	\$2,781	\$2,545	\$2,640	\$2,686
Total	\$35,114	\$35,710	\$36,095	\$35,473	\$36,653	\$31,609	\$34,927	\$34,897	\$35,750	\$36,454	\$35,643

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Drilling	\$9,329	\$8,487	\$7,827	\$7,714	\$8,034	\$9,061	\$11,381	\$13,610	\$13,692	\$19,057
Engineering	\$2,583	\$2,809	\$2,809	\$3,123	\$3,814	\$4,066	\$3,412	\$2,591	\$2,482	\$2,585
G&G	\$413	\$414	\$403	\$392	\$391	\$399	\$423	\$451	\$473	\$475
Install	\$1,069	\$1,051	\$1,325	\$1,522	\$1,134	\$851	\$1,364	\$1,966	\$1,958	\$1,849
OPEX	\$15,983	\$15,866	\$15,379	\$15,153	\$14,655	\$14,485	\$14,471	\$13,797	\$13,566	\$14,253
Platforms	\$2,100	\$2,666	\$2,383	\$2,453	\$3,223	\$3,418	\$2,253	\$1,312	\$1,795	\$2,058
SURF	\$2,800	\$2,870	\$2,862	\$2,651	\$3,272	\$3,491	\$3,031	\$2,334	\$2,170	\$2,257
Total	\$34,276	\$34,163	\$32,987	\$33,007	\$34,523	\$35,771	\$36,336	\$36,061	\$36,136	\$36,534

Source: Quest Offshore Resources, Inc.

Table 21: Project Development Spending by Component – Base Development Scenario (\$Millions)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Drilling	\$6,069	\$6,270	\$8,188	\$7,610	\$9,411	\$7,862	\$8,069	\$8,271	\$10,350	\$12,436	\$12,977
Engineering	\$2,098	\$2,517	\$2,206	\$2,022	\$1,940	\$1,297	\$2,463	\$2,849	\$2,775	\$2,171	\$2,008
G&G	\$183	\$163	\$348	\$368	\$439	\$319	\$372	\$357	\$339	\$393	\$426
Install	\$1,918	\$631	\$762	\$2,791	\$2,995	\$1,442	\$1,084	\$924	\$1,416	\$2,182	\$2,539
OPEX	\$19,533	\$19,466	\$18,920	\$18,355	\$17,836	\$17,845	\$17,766	\$17,629	\$17,326	\$17,263	\$16,671
Platforms	\$3,215	\$4,150	\$3,620	\$2,715	\$2,530	\$1,700	\$2,960	\$3,443	\$3,933	\$3,134	\$2,914
SURF	\$2,098	\$2,513	\$2,051	\$1,613	\$1,503	\$1,144	\$2,213	\$2,617	\$2,418	\$1,968	\$2,027
Total	\$35,114	\$35,710	\$36,095	\$35,473	\$36,653	\$31,609	\$34,927	\$36,089	\$38,557	\$39,548	\$39,563

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Drilling	\$11,106	\$9,223	\$9,272	\$9,274	\$9,156	\$10,943	\$12,255	\$14,324	\$14,845	\$15,305
Engineering	\$2,127	\$2,373	\$2,448	\$2,684	\$3,246	\$3,813	\$3,417	\$2,395	\$1,877	\$1,703
G&G	\$459	\$460	\$448	\$435	\$435	\$443	\$470	\$501	\$526	\$527
Install	\$2,051	\$1,936	\$2,253	\$2,433	\$1,943	\$1,393	\$1,745	\$2,764	\$3,325	\$3,655
OPEX	\$16,810	\$17,390	\$16,854	\$16,500	\$15,973	\$15,983	\$15,924	\$15,990	\$15,676	\$16,148
Platforms	\$3,245	\$3,844	\$3,942	\$3,932	\$4,355	\$5,045	\$4,792	\$3,572	\$3,182	\$2,674
SURF	\$2,282	\$2,396	\$2,207	\$2,394	\$3,003	\$3,376	\$3,055	\$2,161	\$1,712	\$1,946
Total	\$38,080	\$37,620	\$37,424	\$37,652	\$38,111	\$40,596	\$41,657	\$41,726	\$41,142	\$41,557

Source: Quest Offshore Resources, Inc.

Table 22: Government Revenues by Recipient – Proposed Rule Scenario (\$Millions)

Revenue	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Federal Share	\$6,359	\$6,176	\$7,515	\$7,219	\$7,075	\$5,172	\$7,008	\$6,889	\$7,033	\$7,246	\$7,610
State Totals	\$3	\$1	\$0	\$0	\$4	\$5	\$5	\$500	\$500	\$500	\$500
Texas	\$0	\$0	\$0	\$0	\$0	\$1	\$1	\$150	\$150	\$150	\$150
Louisiana	\$1	\$0	\$0	\$0	\$1	\$2	\$2	\$150	\$150	\$150	\$150
Mississippi	\$1	\$0	\$0	\$0	\$1	\$1	\$1	\$125	\$125	\$125	\$125
Alabama	\$1	\$0	\$0	\$0	\$1	\$1	\$1	\$75	\$75	\$75	\$75

Revenue	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Federal Share	\$7,767	\$8,057	\$8,240	\$8,389	\$8,664	\$9,080	\$9,365	\$9,648	\$9,988	\$10,370
State Totals	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500
Texas	\$150	\$150	\$150	\$150	\$150	\$150	\$150	\$150	\$150	\$150
Louisiana	\$150	\$150	\$150	\$150	\$150	\$150	\$150	\$150	\$150	\$150
Mississippi	\$125	\$125	\$125	\$125	\$125	\$125	\$125	\$125	\$125	\$125
Alabama	\$75	\$75	\$75	\$75	\$75	\$75	\$75	\$75	\$75	\$75

Source: Quest Offshore Resources, Inc.

Table 23: Government Revenues by Recipient – Base Development Scenario (\$Millions)

Revenue	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Federal Share	\$6,359	\$6,176	\$7,515	\$7,219	\$7,075	\$5,172	\$7,008	\$7,125	\$7,950	\$7,762	\$8,328
State Totals	\$3	\$1	\$0	\$0	\$4	\$5	\$5	\$500	\$500	\$500	\$500
Texas	\$0	\$0	\$0	\$0	\$0	\$1	\$1	\$150	\$150	\$150	\$150
Louisiana	\$1	\$0	\$0	\$0	\$1	\$2	\$2	\$150	\$150	\$150	\$150
Mississippi	\$1	\$0	\$0	\$0	\$1	\$1	\$1	\$125	\$125	\$125	\$125
Alabama	\$1	\$0	\$0	\$0	\$1	\$1	\$1	\$75	\$75	\$75	\$75

Revenue	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Federal Share	\$9,688	\$9,018	\$9,453	\$9,807	\$10,409	\$10,747	\$11,280	\$11,722	\$12,277	\$12,754
State Totals	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500
Texas	\$150	\$150	\$150	\$150	\$150	\$150	\$150	\$150	\$150	\$150
Louisiana	\$150	\$150	\$150	\$150	\$150	\$150	\$150	\$150	\$150	\$150
Mississippi	\$125	\$125	\$125	\$125	\$125	\$125	\$125	\$125	\$125	\$125
Alabama	\$75	\$75	\$75	\$75	\$75	\$75	\$75	\$75	\$75	\$75

Source: Quest Offshore Resources, Inc.

Table 24: Total Employment – Base Development and Proposed Rule Scenarios in Thousands

Scenario	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Direct	139	139	136	140	142	118	134	139	146	148	148
Base Indirect	270	271	272	272	279	245	266	280	294	301	300
Proposed Direct	139	139	136	140	142	118	134	134	136	138	135
Proposed Indirect	270	271	272	272	279	245	266	277	281	285	278
Base Total	409	409	408	412	421	363	400	419	441	449	449
Proposed Total	409	409	408	412	421	363	400	412	417	423	413

Scenario	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Direct	144	145	145	148	150	158	159	156	154	155
Base Indirect	290	287	285	286	288	303	309	311	307	312
Proposed Direct	131	133	130	131	137	141	139	135	135	136
Proposed Indirect	267	266	257	257	266	274	278	276	275	278
Base Total	434	433	430	434	438	461	469	467	460	467
Proposed Total	398	399	387	388	403	415	418	411	409	414

Source: Quest Offshore Resources, Inc.

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Attachment for 250.414 (c) (1)**Guidance for Surface and Downhole Mud Weight**

When using Synthetic Based Mud (SBM), there may be a significant difference between Surface Mud Weight (SMW) and Downhole Mud Weight (DHMW) due to compressibility and thermal effects. This delta must be accounted for on deep, complex wells on a case-by-case basis. However, many wells are drilled with Water Based Mud (WBM) or to shallow depths with SBM where the delta is inconsequential. Therefore, the requirement to use DHMW in this clause is overly prescriptive as it will add unnecessary complexity to all wells, thereby diluting the focus of engineering and operational personnel on more pressing process safety issues.

- The following terms are clearly defined in the diagrams below:
 - Surface Mud Weight (SMW)
 - Downhole Mud Weight (DHMW)
 - Equivalent Static Density (ESD)
 - Equivalent Circulating Density (ECD)

Figure 1

The surface mud weight is measured at the surface.

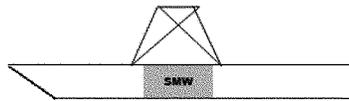
**Surface Mud Weight (SMW)**

Figure 2
The Downhole mud weight is affected by various factors.

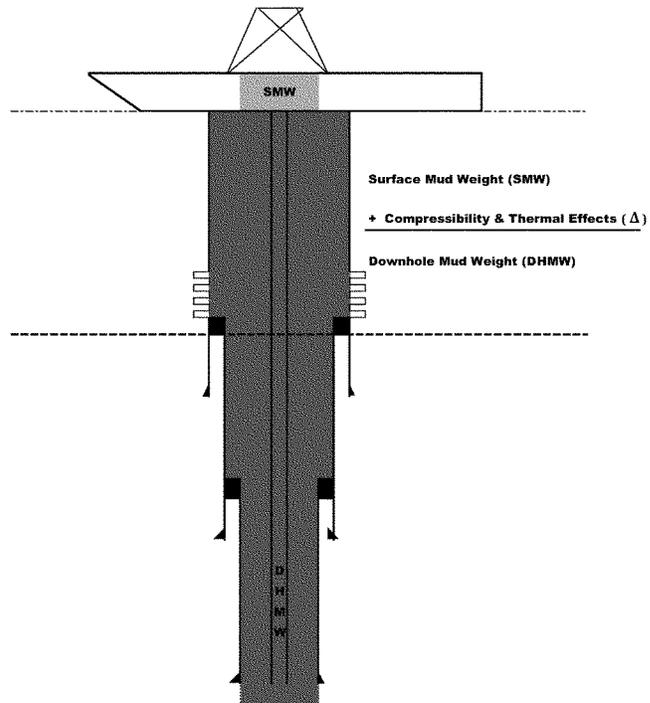


Figure 3
The equivalent static density is the downhole mud weight with the cuttings load.

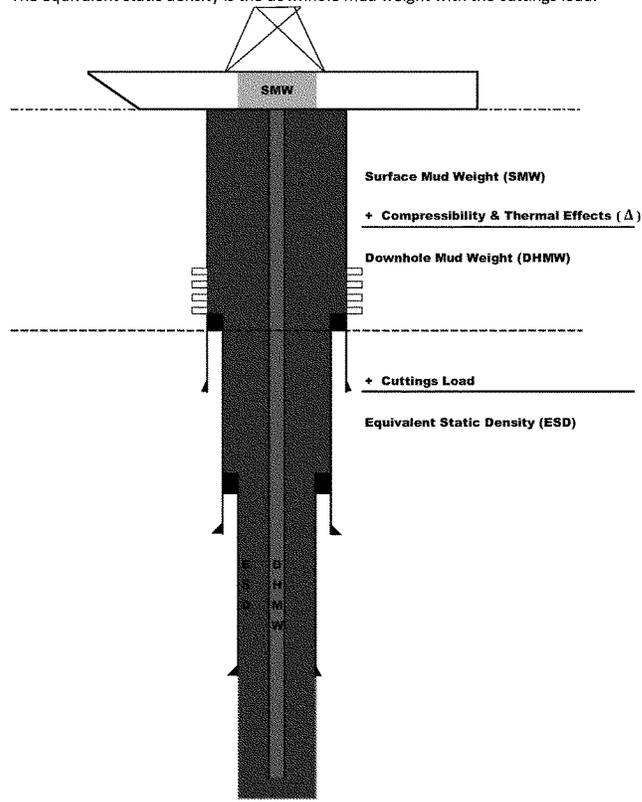
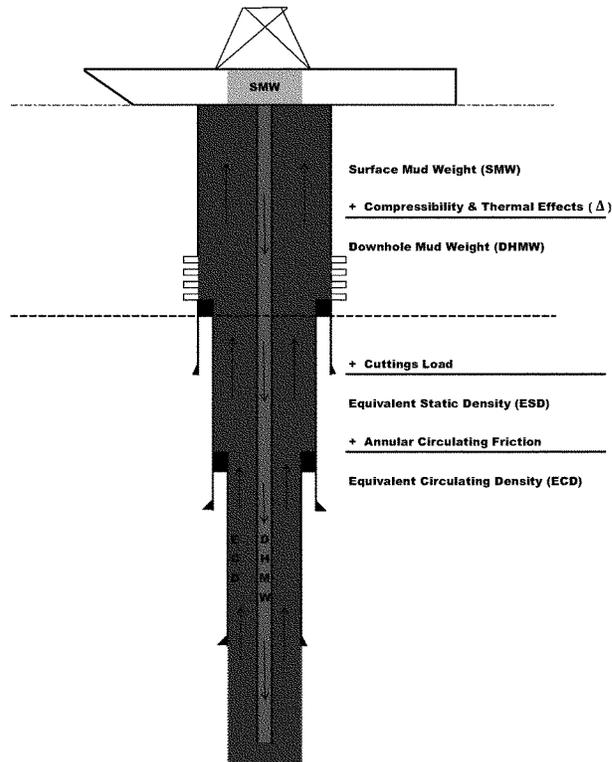


Figure 4

The ECD is the ESD plus the effect of annular circulating friction. When recorded by a tool, a calculation is required to determine the ECD at any depth other than the tool depth. (i.e., when the tool is measuring ECD below the casing shoe).



In summary, many calculations are required to calculate downhole mudweights. Examples include but are not limited to:

- $DHMW = SMW + H$ (Mud Compressibility & Thermal Effects)
- $ESD = DHMW + \text{Cuttings Load}$
- $ECD = ESD + \text{Annular Friction}$ or
- $ECD = DHMW + \text{Cuttings Load} + \text{Annular Friction}$

Figure 5

How to determine the effect of mud compressibility and thermal effects at a drilling rig

- Prior to performing the PIT, 3 ESD's are pumped up and averaged (ESD_a)
- At this point the cuttings load in the well is negligible, so

$$ESD_a = DHMW$$

- Therefore

$$\Delta = ESD_a - SMW$$

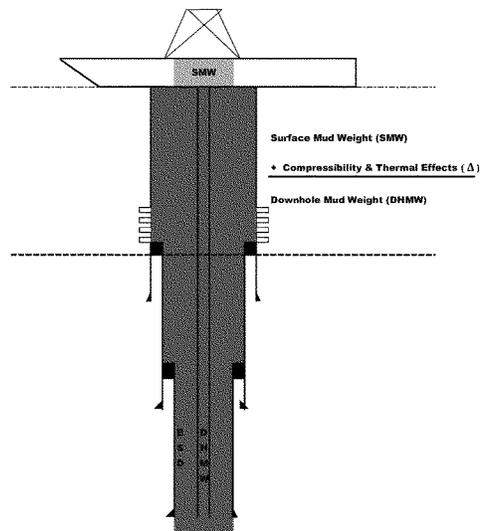
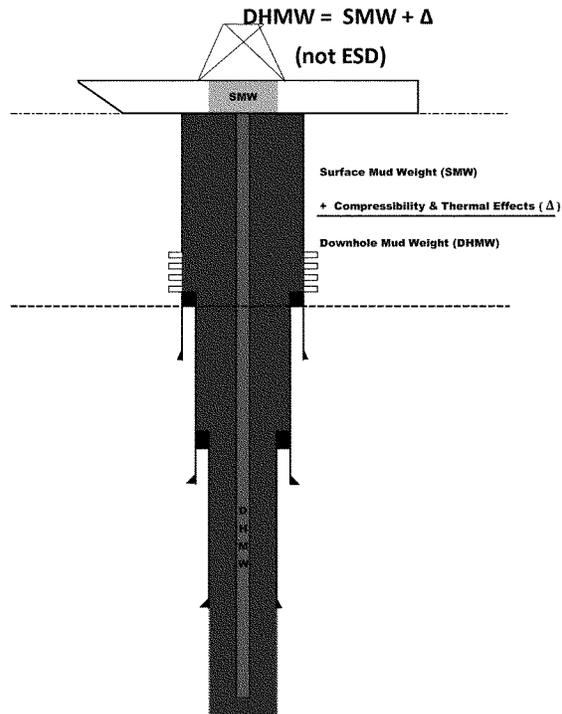


Figure 6

Correct usage requires a clear understanding of downhole conditions to determine the DHMW in relation to a weak point or shoe in the well while drilling.
This DHMW can be used to assure that the Drilling margin is maintained as compared to the weakest know point in the interval as per the PP/FG curve (always in DHMW).



Clarification for usage of delta

- For Lessees that are using WBM, OR t the Drilto shallow depths with SBM ("inconsequential delta" -no PWD or hydraulic modelling required):

$$SMW + \text{delta} = W + d$$

$$12.0+ \text{de } 2. + \text{delta}$$

- For Lessees that are drilling deep, deepwater wells (r wells (are drilling deep, deepwater wells (ow depths with SBM

$$SMW + \text{delta} = W + d$$

$$12.0+ \text{de } 2.0+ + \text{delta}$$

Attachment for 250.414 (c) (2)**Drilling Margin**

Industry acknowledges the safety concerns BSEE has regarding drilling margins and the need for increased vigilance. Avoidance of incidents is paramount, especially in difficult hole sections. Industry has consistently shown the ability to be able to drill without arbitrary prescriptive safety margins, through safe drilling practices.

For example, API 92L addresses the effects of drilling margins in difficult hole sections.

"Drilling margin only applies to operations conducted while drilling. The drilling margin is the difference between the mud weight in use and the lowest exposed formation fracture gradient. The fracture gradient is first measured at the casing shoe when it is drilled out using either a formation integrity test (FIT), which is taken to a pre-determined pressure, or a leakoff test (LOT), whereby whole mud is pumped into the formation to establish the formation strength. Operators should use local knowledge to determine which test (FIT or LOT) best supports the well construction objectives. The lowest exposed fracture gradient may also be measured after the shoe test in open hole with an ECD FIT test.

Some of the factors affecting the selection of a drilling margin include depth, open-hole interval exposure, temperature, fracture gradient and mud properties (mud weight without cuttings). The formation strength component of a GOM drilling margin may be negatively affected by a LOT that is conducted using a synthetic or an oil base mud.

A prescriptive fixed safe drilling margin can result in unintended consequences as follows:

- 1. A 0.5 ppg safe drilling margin at 7,700 ft TVD results in a 200 psi pressure differential, while at 30,000 ft TVD this safe drilling margin increases to a 780 psi difference. At shallower depths than 7,700 ft, a 0.5 ppg safe drilling margin is difficult to implement due to the narrow margin between fracture gradient and pore pressure.*
- 2. A drilling margin of 2% of the lowest exposed fracture gradient could be used to accommodate the changing fracture and pore pressure conditions within a drilling well. Unfortunately, even this approach falls short of completely addressing the challenges provided by GOM wells, where well depths can vary from less than 5,000' to greater than 35,000' and where formation strengths vary significantly with lithology (e.g., salt, limestone, sand, shale) and water depth.*

Therefore, prescriptive drilling margins are not recommended, rather a risk assessment should be performed to establish safe drilling margins for each well and for each drilling interval within the well.

Using a relevant drilling margin should result in well control and kick recognition being maintained when drilling ahead with losses. The drilling margin should be risk-assessed and calculated based on sound engineering practices. Bottom hole pressure (hydrostatic pressure plus applied surface pressure, as applicable) must be greater than pore pressure. The drilling margin should be reassessed if lost circulation conditions change."

ATTACHMENT D

Another unintended consequence is that an operator may be forced to drill very near to balance to maintain the mandated "Safe" Drilling Margin in order to achieve the well objectives, incurring unanticipated, unnecessary risks. Alternatively BSEE could use the definition of drilling margin as defined in API 96. This will eliminate the effect of mud weight when determining a safe drilling margin. API 96 defines drilling margin as "*the difference between the maximum pore pressure and the minimum effective fracture pressure. It is used while drilling and can be determined for any point within an open hole interval.*" Alternatively, to meet the "Safe" drilling margin requirement, an operator may be forced into setting surface casing deeper into a pressured environment to obtain the required "Safe" drilling margin for the next hole interval.

As already noted, many of the wells in Deepwater set every string of pipe available to get the required casing size for production equipment at total depth. Industry has optimized the use of the current 18 3/4" wellhead and 18 3/4" BOP sizes such that there is not any space in the wellhead for more casing strings to be added. This optimization has been intensely pursued by industry for the past 16 years. For the deeper depth wells there are no shallow pays, all the productive interval is near total depth. The casing setting depths are critical. To stop short at any point puts the entire well in jeopardy. For shelf wells and deepwater platforms, when drilling through depleted zones, these are normally sidetracks and the casing size is already small, to set extra strings of pipe may not be possible when a reasonable size casing for completion is required.

A review of 175 OCS wells drilled after June 2010 found that 33% required less drilling margin than the proposed rules allow.

The 0.5 ppg safe drilling margin was twice mentioned in the "Increased Safety Measures For Energy Development on the Outer Continental Shelf" (Published May 27, 2010). The 0.5 ppg margin has no technical correlation to deepwater wells or very shallow wells. Macondo was not in a drilling mode and therefore any prescriptive safe drilling margin would not have had a material difference in the loss of well control event.

The industry has clearly demonstrated their ability to safely drill at lower drilling margins using recognized practices and procedures such as those found in API 92L.

Response to Proposed Well Control Rule**§250.420(c)(2)****Casing Cementing Workgroup**

Proposed Rule: You must use a weighted fluid to maintain an overbalanced hydrostatic pressure during the cement setting time, except when cementing casings or liners in riserless hole sections.

Proposed Change: You must consider practices which promote the isolation of potential flow zones.

Response 1: The proposed rule will have unintended consequences:

- Increasing mud weight to replace pressure reduction during cement hydration increases the risk of lost circulation, which may result in a failure to attain the top of cement (TOC) necessary for zonal isolation and casing support.
- Increasing mud weight to replace pressure reduction during cement hydration will reduce the density difference between mud, spacer and cement that is otherwise utilized to achieve effective mud removal from the cemented section of the well bore. This reduced difference increases the risk of a leaving a mud channel that permanently compromises zonal isolation (API Standard 65-2, 2nd Edition, Section 5.6.5.2).

Supporting information: Simulations for a group of actual wells demonstrates that wells which can be successfully cemented using current practice cannot be successfully cemented with higher fluid density.

Response 2: The proposed rule is not technically sufficient because:

- Although increasing the pressure applied to the cement slurry increases initial overbalance pressure this pressure is not transmitted through the cement slurry as the cement become self-supporting during cement's Critical Gel Strength Period (cf. SPE 11206, SPE 11416 and calculated in API Standard 65-2, 2nd Edition, Sections A13 and A14).
- Therefore, in the absence of a cement design that addresses the Critical Gel Strength Period, additional hydrostatic overbalance of any amount may be insufficient to address potential flow zones.

Supporting information:

Cooke, C. E., Kluck, M. P. and Medrano, R., "Field Measurements of Annular Pressure and Temperature during Primary Cementing," paper SPE 11206 published in JPT, pp. 1429-1439, August 1983

Cooke, C. E., Kluck, M. P. and Medrano, R., "Annular Pressure and Temperature Measurements Diagnose Cementing Operations," paper SPE 11416 published in JPT, pp. 2181-2186, December 1984

API Standard 65-2, 2nd Edition, Sections A13 and A14 discuss SPE 11206 and SPE 11416, the phenomenon of loss of hydrostatic pressure after cement placement and some of the key results of Cooke's study.

Stiles, D. A., “Successful Cementing in Areas Prone to Shallow Water Flows in Deep-Water Gulf of Mexico,” paper OTC 8305, Presented at the 1997 Offshore Technology Conference, Houston, Texas May 5-8. This paper describes a slurry’s critical hydration period (called “critical gel strength period”, CGSP in API 65-2) in the larger context of total cement system performance and effective mud removal practices.

Mueller, D. T., “Redefining the Static Gel Strength Requirements for Cements Employed in SWF Mitigation,” paper OTC 14282 presented at the 2002 Offshore Technology Conference, Houston, Texas May 6-9. This paper describes the concept of the critical gel strength (called critical static gel strength CSGS in API 65-2) and illustrates that gel strength value which results in the decay of hydrostatic pressure to the point which pressure is balances (hydrostatic pressure equals pore pressure) can be significantly less than the 100 lbf/100 ft² value used in the traditional definition of transition time.

Nelson, Erik B. and Guillot, Dominique, editors, “Well Cementing”, Chapter 9: Annular Fluid Migration, Stiles, D. A., 2006. This text is one of the definitive books describing well cementing technology. Chapter 9 describes the consequences and physical process of gas migration, factors affecting migration and methods of predicting it as well as solutions for combatting it and laboratory testing methods.

Response 3: The proposed rule may prohibit the judicious use of unweighted preflushes as a tool for equivalent circulating density (ECD) management.

- In certain wells, pumping a weighted spacer followed by a lighter weight turbulent-flow flush has been used to manage ECD and promote hole cleaning. In such cases, the hydrostatic pressure from weighted spacer ahead compensates for the reduced hydrostatic pressure from the flush and maintains the overbalance pressure in the well. The proposed rule may prohibit optimal ECD Management and hole cleaning.

Supporting information:

Khalilova, P., Koons, B., Lawrence, D., and Elhancha, A., “Newtonian Fluid in Cementing Operations in Deepwater Wells: Friend or Foe?” paper SPE 166456, 2013. The paper describes the factors to be considered when designing cement jobs using turbulent flow fluids as well as the results of five field applications of the technique.

Response 4: The proposed rule is not technically necessary

The purpose of API Standard 65-2, 2nd Edition is to describe methods of isolating potential flow zones during well construction. This standard is already incorporated into the regulations by reference. Proper slurry design coupled with effective mud removal described in API Standard 65-2, 2nd Edition is sufficient to meet the goal of the proposed regulation.

ATTACHMENT F

Operator Response to CFR 250.420(c)(2) as per proposed new BSEE Well Control Rule

Introduction

In response to the proposed CFR 250.420(c)(2) well control rule, the below comparison simulations were run on a typical deep-water development well production liner cement job that was successfully performed in 2013 to isolate multiple HC zones in the annulus without any losses (see below "BASE DESIGN – CASE A"). In order to accommodate the new code as stated in CRF250.420(c)(2), a "REVISED DESIGN – CASE B" is also presented below which incorporates a weighted fluid ahead of the cement to offset the hydrostatic pressure loss during the cement setting process – assuming the cement goes from a 16.3ppg density to 8.34ppg density. Incorporating this weighted fluid ahead of the cementing fluid train during placement significantly enhances the potential for losses and subsequent inability to isolate the HC zones in the annulus.

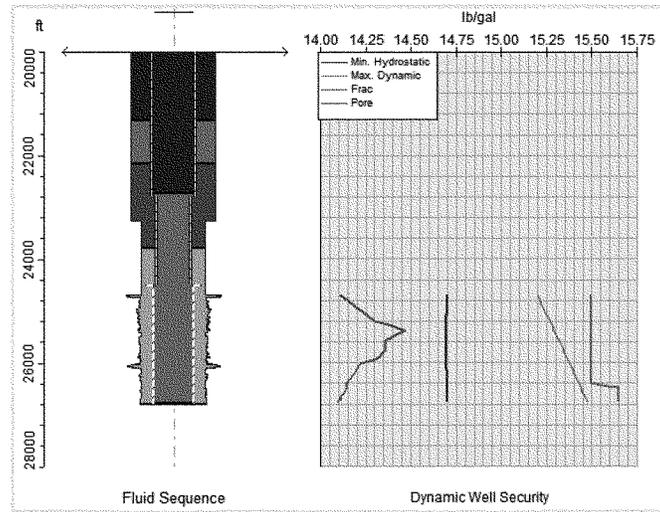
The 1st graph presented in each case shows a snapshot of the maximum ECD during cement placement across the entirety of the wellbore (the green line signifying the maximum ECD and the brown line signifying the fracture gradient of the sands throughout the interval).

The 2nd set of graphs presented in each case show the simulated ECDs at the lowest fracture gradient sand and at casing TD. The light blue line represents the maximum dynamic ECD and the red line represents the fracture gradient at that depth.

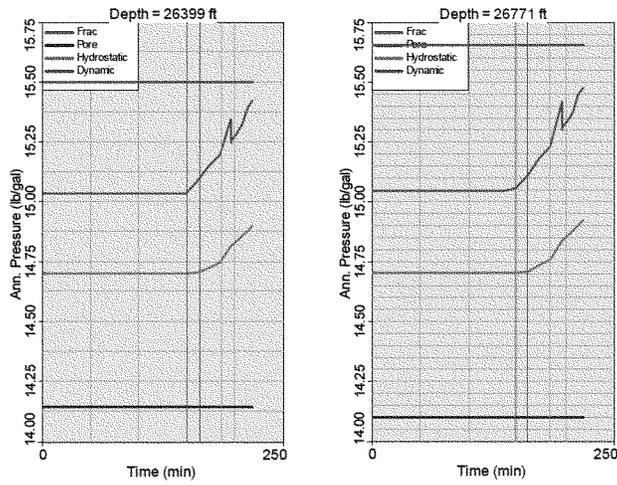
As evidenced by the 2nd case below, incorporating the weighted fluid ahead of the cementing fluids could have jeopardized the successful isolation of the HC zones in the interval due to the increase in cementing ECD and associated lost circulation.

Typical Deepwater Development – CASE A

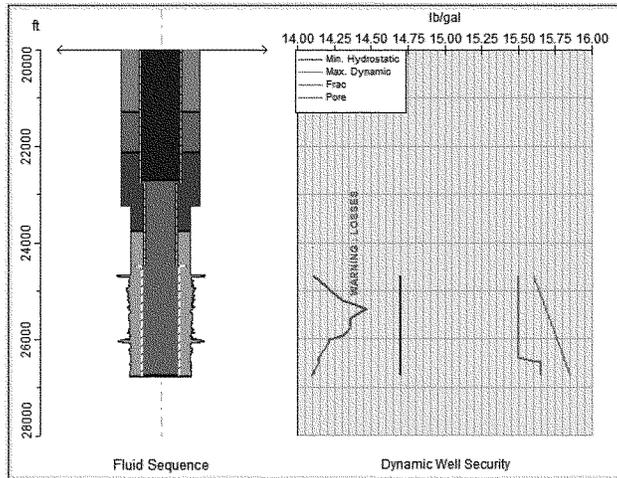
BASE DESIGN



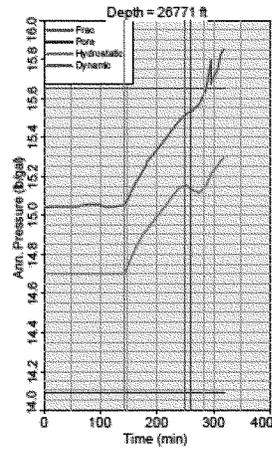
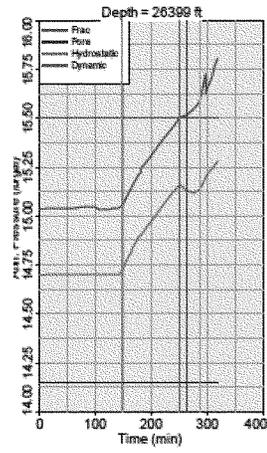
ATTACHMENT F



REVISED DESIGN – incorporating 300bbl 16.4ppg slug to restore BASE CASE overbalance pressure assuming cement column density to 8.34ppg



ATTACHMENT F

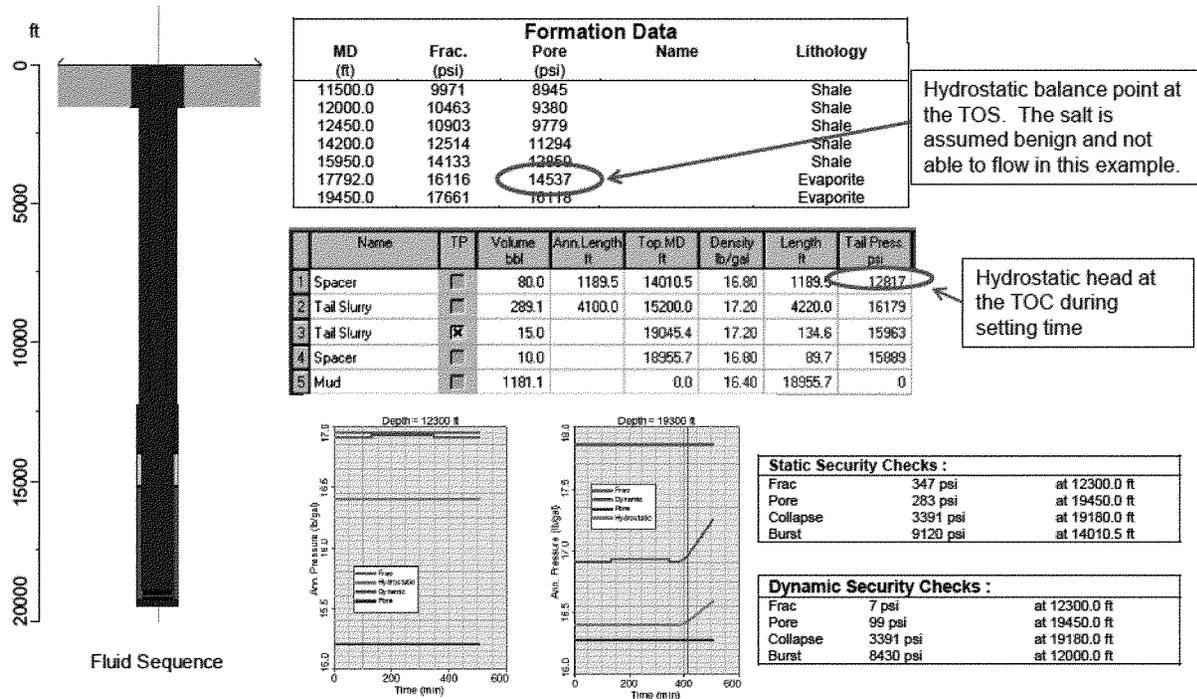


ATTACHMENT G

BSEE Proposed Rule Change Modeling CFR 250.420

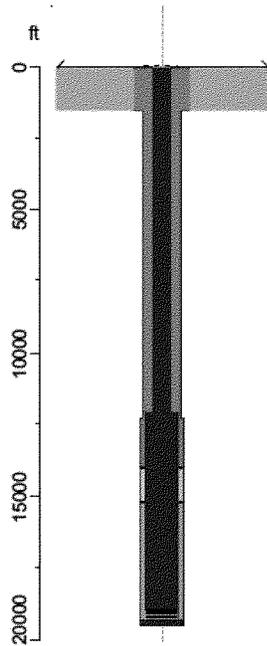
ATTACHMENT G

Example #1 –1450' Water Depth (Current Design)



ATTACHMENT G

Example #1 – Proposed BSEE language design

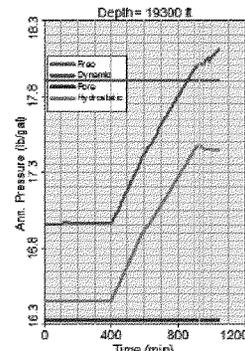
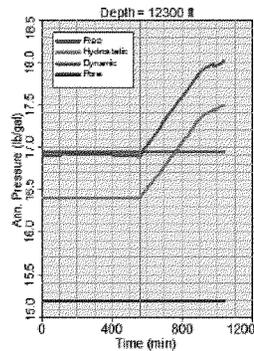


Fluid Sequence

	Name	TP	Volume bbl	Ann.Length ft	Top MD ft	Density lb/gal	Length ft	Tail Press. psi
1	Heavy Mud	<input checked="" type="checkbox"/>	1643.9	13926.5	84.0	17.50	13926.5	12629
2	Spacer	<input checked="" type="checkbox"/>	80.0	1189.5	14010.5	16.80	1189.5	13611
3	Tail Slurry	<input checked="" type="checkbox"/>	289.1	4100.0	15200.0	0.10	4220.0	13630
4	Tail Slurry	<input checked="" type="checkbox"/>	15.0		19045.4	0.10	434.6	15889
5	Spacer	<input checked="" type="checkbox"/>	10.0		18955.7	16.80	89.7	15889
6	Mud	<input checked="" type="checkbox"/>	1181.1		0.0	16.40	18955.7	0

Hydrostatic balance (14537 psi) can not be achieved with 17.5 ppg mud back to surface.

Cement density assumed to be 0.1 ppg when setting



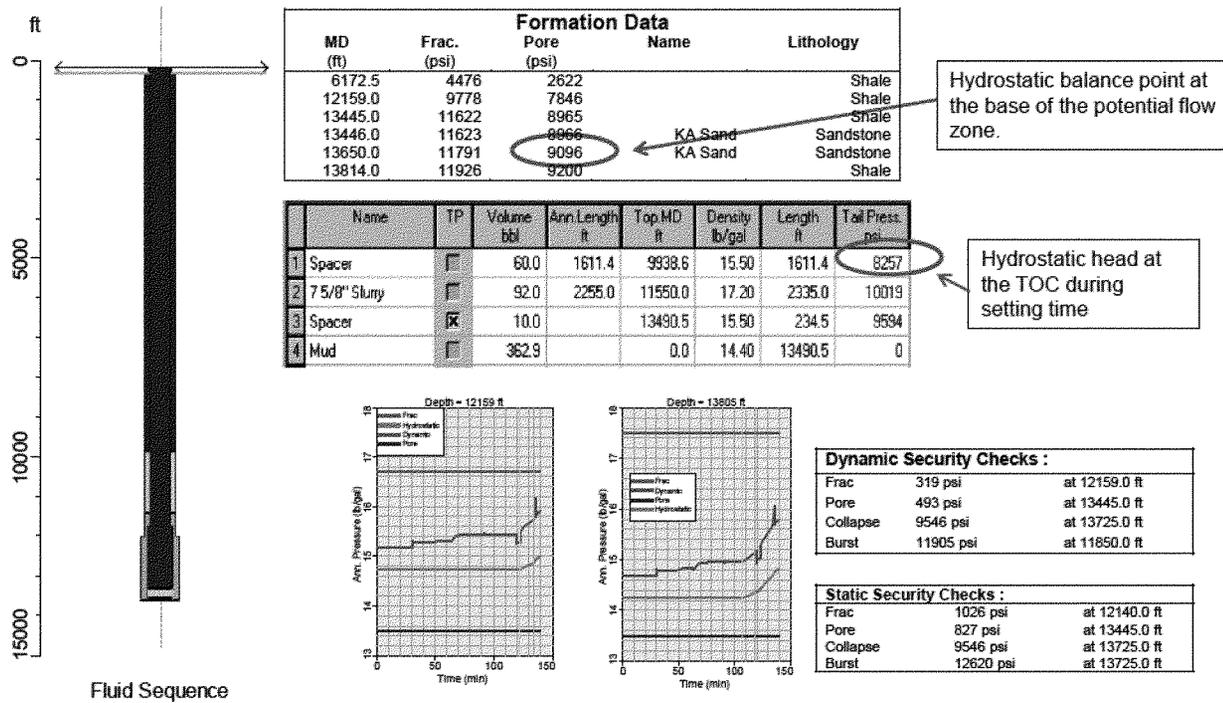
ECD plots assume cement density (17.2 ppg) during placement

Dynamic Security Checks :		
Frac	-675 psi	at 12300.0 ft
Pore	99 psi	at 19450.0 ft
Collapse	2598 psi	at 19180.0 ft
Burst	8317 psi	at 12000.0 ft

Static Security Checks :		
Frac	-351 psi	at 12300.0 ft
Pore	1077 psi	at 19450.0 ft
Collapse	2598 psi	at 19180.0 ft
Burst	9190 psi	at 19180.0 ft

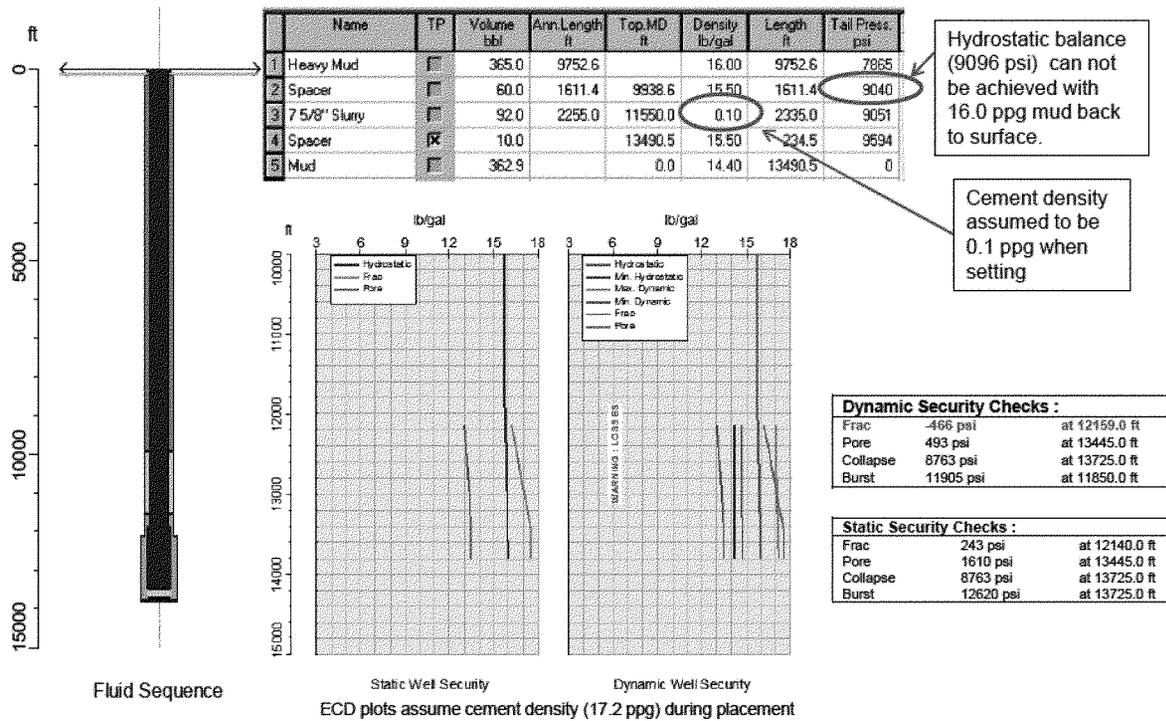
ATTACHMENT G

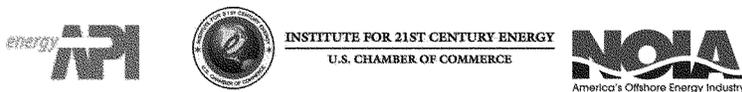
Example #2 – Shelf (Current Design)



ATTACHMENT G

Example #2 – Proposed BSEE language design





API
1220 L Street NW
Washington DC, 20005

Institute of 21st Century Energy
1615 H Street, N.W.
Washington, D.C. 20062

National Ocean Industries Association
1120 G Street, NW • Suite 900
Washington, DC 20005

May 27, 2015

BSEE
Attention: Regulations and Standards Branch
45600 Woodland Road
Sterling, Virginia 20166

Re: [Docket ID: BSEE-2013-0011]

Bureau of Safety and Environmental Enforcement, 30 CFR Parts 250 and 254; Bureau of Ocean Energy Management, 30 CFR Part 550

Oil and Gas and Sulphur Operations on the Outer Continental Shelf—Requirements for Exploratory Drilling on the Arctic Outer Continental Shelf, RIN: 1082-AA00

To the Regulations and Standards Branch:

The Bureau of Safety and Environmental Enforcement (BSEE) and the Bureau of Ocean Energy Management (BOEM) jointly published proposed new requirements to regulations for exploratory drilling and related operations on the Outer Continental Shelf (OCS) seaward of the State of Alaska (Alaska OCS). The proposed regulations were published in the Federal Register February 24, 2015 at 80 FR 9915 (Volume 80, Number 36, Pages 9915–9971).

With this letter, API, the U.S. Chamber of Commerce's Institute for 21st Century Energy, and National Ocean Industries Association (NOIA) ("the Associations") provide comments to this rulemaking. API is a national trade association representing over 625 member companies involved in all aspects of the oil and natural gas industry. API's members include producers, refiners, suppliers, pipeline operators, and marine transporters, as well as service and supply companies that support all segments of the industry. API and its members are dedicated to meeting environmental requirements, while safely and economically developing and supplying energy resources for consumers. API members have significant interest in ensuring that there are future opportunities for offshore oil and natural gas exploration and development in the United States ("U.S.") so that the nation can capitalize on industry expertise that has been garnered through years of successful and beneficial exploration, development and production of domestic OCS oil and natural gas resources, including the resources that are believed likely to be found in the Alaska OCS. API members are engaged in exploration and production for crude oil and natural gas in the OCS portions of the Beaufort and Chukchi Seas, and hold leases issued by BOEM in these areas.

The mission of the U.S. Chamber of Commerce's Institute for 21st Century Energy is to unify policymakers, regulators, business leaders, and the American public behind a common sense energy

An equal opportunity employer.

strategy to help keep America secure, prosperous, and clean. Through policy development, education, and advocacy, the Institute is building support for meaningful action at the local, state, national, and international levels. The U.S. Chamber of Commerce is the world's largest business federation representing the interests of more than 3 million businesses of all sizes, sectors, and regions, as well as state and local chambers and industry associations.

NOIA, founded in 1972, represents more than 325 companies among all segments of the offshore industry with an interest in the exploration and production of both traditional and renewable energy resources on the nation's outer continental shelf (OCS). NOIA's mission is to secure reliable access and a fair regulatory and economic environment for the companies that develop the nation's valuable offshore energy resources in an environmentally responsible manner.

1. Overview

The comments set forth in this letter describe approaches that The Associations believe would best assure orderly, safe and environmentally responsible development of energy resources in the Alaska OCS for our nation's economic and energy security, and for the benefit of the people of the north and the United States as a whole. Our comments are informed by the long experience of our industry with exploration, development and production operations in the Arctic, and by – among other analyses of that experience – the report, *Arctic Potential: Realizing the Promise of U.S. Arctic Oil and Gas Resources*, released by the National Petroleum Council March 27, 2015 (NPC Arctic Report). The NPC Arctic Report was commissioned by the request of the Secretary of Energy, Ernest J. Moniz, to the NPC October 23, 2014, and is a comprehensive multi-stakeholder study that considers the research and technology opportunities to enable prudent development of U.S. Arctic oil and gas resources.

2. Access to Oil and Gas Resources in the Alaska OCS under Balanced and Science-Based Regulations Is Essential to the Nation's Economy and Energy Security

As acknowledged in the NPC Arctic Report, the Alaska OCS, including the Chukchi and Beaufort Seas off Alaska, is highly prospective for discovery of new world class hydrocarbon resources. Development of new oil and gas resources is a critical state and national interest. The offshore oil potential of the Alaska OCS is similar to Russia and larger than that of Canada and Norway. The Alaska OCS is estimated to have 48 BBOE of offshore undiscovered conventional resource potential, with over 90% of this in less than 100 meters of water. Furthermore, the Chukchi and Beaufort Sea OCS combined represent over 80% of the total U.S. Arctic offshore conventional potential. The Chukchi Sea offers more potential resources than any other undeveloped U.S. energy basin. The Beaufort Sea also provides among the largest potential undiscovered resource accumulations in the U.S. Together, the oil and natural gas resource potential represented by the Chukchi and Beaufort Seas exceeds the combined resource estimates for the Atlantic and Pacific OCS.

The search for energy resources in the Arctic is not new. The long record of our industry's exploration and production operations in the region demonstrates that exploration and development of oil and natural gas resources in the Alaska OCS can take place in a safe and environmentally responsible manner; can enable the protection of habitat, wildlife, and subsistence resources; and is respectful of the way of life and the communities of the people living in the region. This long record includes exploration, development, production, and transport, and has resulted from continuous technology advances and learnings from experience. Approximately 440 exploration wells have been drilled in Arctic waters overall, including 35 in the Alaska OCS.

America's Alaska OCS can make an important contribution to sustaining our nation's overall crude oil supplies at a time in the future when Lower 48 production – now flourishing due to industry's development of technologies to extract oil and natural gas from shale, tight sandstone and other formations previously

thought to be non-economic – is projected to be in decline. As discussed in depth in the NPC Arctic Report, most of the U.S. Arctic offshore oil and gas potential can be developed safely using existing field-proven technology. It is critical that regulation of operations on the Arctic OCS recognize the importance of the resource potential at stake, the record of the operating experience that demonstrates that these resources can be developed in a way that does not harm the Arctic environment nor prevent subsistence, and other uses of that environment. Given the resource potential and long timelines required to bring Arctic resources to market, Arctic exploration today may provide a material impact to U.S. oil production in the future, potentially averting decline, improving U.S. energy security, and benefitting the regional and overall U.S. economy.

Studies show that development of the Alaska OCS would increase economic activity and jobs. Northern Economics in association with the University of Alaska-Anchorage assessed that OCS development would add approximately \$145 billion in new payroll for U.S. workers and \$193 billion or more in new local, state, and federal government revenue combined over 50 years.¹ The projected net revenues to the state of Alaska from OCS development could be about \$6.6 billion (2007\$). Today oil and gas development is one third of the state of Alaska's economic activity and provides about 90% of the state's general revenue. The North Slope Borough oil and gas property taxes have exceeded \$180 million annually since 2000, representing about 60% of their annual operating budget. One-third of Alaska's jobs—127,000—are oil-related and depend on oil production.

The economic assessment put forward in the proposed rules significantly and systematically underestimates the potential impact to industry which is likely to challenge the economics of potential large scale investments. The assessed ~\$1 billion cost to industry over the 10 year assessment period fails to address the impacts of shortening the effective drilling season (driven primarily by a same-season relief well requirement) and utilizes assumed spreadrates for drilling and emergency response facilities that are far lower than demonstrated by industry experience. Across the board, the agencies' estimated costs are drastically low, sometimes by several orders of magnitude. After adjusting the proposed economic assessment on these two factors noted above alone, the estimated cost to industry is estimated at \$10 - 20 billion, and could potentially be higher. Such a cost burden would establish economic barriers that would profoundly reduce the ability for this nation to develop its arctic resources.

Moreover, the agencies' benefits justification for these costs is based on the agencies' faulty premise that a catastrophic oil spill will take place on Alaska's OCS in the next ten years. BOEM's previous analyses, and most recently its analysis undertaken as part of the Second Supplemental Environmental Impact Statement (SEIS) in support of Lease Sale 193, flatly contradict this assumption, and the agencies provide no support for the assumption. Indeed, the Lease Sale 193 SEIS concludes that there is a less than one percent chance that even a large oil spill (>1000 barrels) will occur during exploration. *See* <http://www.boem.gov/Risk-and-Benefits-in-the-Chukchi-Sea/>.

Of central importance in our nation's ability to benefit from the resource endowment of the Alaska OCS will be regulatory approaches that establish alignment of policy and consistency in regulation among agencies with jurisdiction over operations, and that support decision making with information and processes that take advantage of advances in science and technology. As the NPC stated in its report:

“Oil and gas exploration and development in the Arctic is extensively regulated. Drilling an offshore exploration well in the Arctic currently requires permitting from at least 12 principal state and federal agencies; progressing offshore development in the Arctic would require around 60 permit types through 10 federal agencies. Regulations should be adaptive to reflect advances in

¹ *Economic Analysis of Future Offshore Oil and Gas Development: Beaufort Sea, Chukchi Sea, and North Aleutian Basin*, by Northern Economics in association with the Institute of Social and Economic Research at the University of Alaska-Anchorage, Feb. 2011. The study notes that “[t]he scenarios used were based in part on the scenarios discussed by the Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) in published Environmental Impact Statements (EIS) and other materials. . . . The recent Draft Environmental Impact Statement for the *Beaufort and Chukchi Sea Planning Areas, Oil and Gas Lease Sales 209, 212, 217, and 221* was issued after the analysis for this report was completed. The scenarios used in this report are based on earlier scenarios and other material that are broader in scope and duration than the November 2008 draft EIS.”

technology and ecological research, and achieve an acceptable balance considering safety, environmental stewardship, economic viability, energy security, and compatibility with the interests of the local communities. Prescriptive regulation may inhibit the development of new, improved technologies by suppressing the potential opportunity that drives advancement.”²

With this letter, The Associations offer recommendations to best assure that this “acceptable balance” can take shape.

3. The Associations Urge Adoption of Regulations That Accommodate a Broader Range of Equipment and Drilling Platforms

The proposed rules limit their consideration to a particular approach to drilling based on use of a floating rig, and the result is prescriptive rules that require particular equipment to the exclusion of other approaches that could be safely and effectively used. In a great many areas in the Arctic OCS, the conditions at prospective drill sites allow use of alternatives to floating rigs. Nevertheless the proposed regulations appear to be written from the perspective that the only foreseeable approach to exploration drilling projects in the region will involve floating rigs, and equipment and support systems compatible with floating rigs. This makes these Arctic-specific rules different than those that apply to other areas of the OCS and there is no Arctic-specific reason or justification for this.

In fact, wells in shallow waters of Beaufort Sea have been safely drilled in the past with bottom-founded or iced-in rigs, but such rigs may not be able to accommodate a containment dome or a mudline cellar, and so use of this type of rig would likely be precluded by the proposed rules. Jackup rigs are safe and viable in waters up to 300 feet deep in the Chukchi Sea—but the requirements prescribed in the proposed rules may eliminate their potential use, without providing any basis for such a limitation on operators’ exploration plans. The rules should be more flexible and based on performance standards, in order to accommodate different, new, and better approaches.

It’s not uncommon for BSEE to adopt regulations that accommodate different rig types, but for reasons unexplained, BSEE and BOEM did not take that approach here. The result is a rulemaking proposal that unnecessarily precludes approaches that do not align with the prescriptive rules it contains, but that based on industry’s operating experience in the region can be shown to be safe and effective. In some cases, the proposed regulations refer to the possibility of alternative equipment, but there are no standards or criteria to provide any guidance on how alternative equipment would be evaluated for approval. Overall, if the regulatory focus is on floating rigs, then the rules should be applicable only to floating rigs. Alternatively, the rules could adopt a broader, more flexible and performance-based approach such as found in rules applicable to other areas of the OCS which do not prejudice the choice of drilling platforms.

4. The Associations Urge Withdrawal of the Proposed Requirement that Operators Submit an Integrated Operations Plan (IOP)

The Associations request that BOEM not adopt proposed Section 550.204 that requires that operators proposing exploratory drilling activities on the Arctic OCS submit an Integrated Operations Plan (IOP) 90 days prior to filing an EP (Exploration Plan). The EP, required under OCSLA, is meant to provide the agency the information necessary to achieve its regulatory objectives pursuant to OCSLA requirements governing an operator’s planned activities. In the event the EP does not meet the intended requirements, the

² National Petroleum Council. *Arctic Potential: Realizing the Promise of U.S. Arctic Oil and Gas Resources*. 2015.

appropriate steps should be taken to amend the EP process, rather than creating additional regulatory requirements.

Much of the information required in the IOP under proposed Section 550.204 is already gathered and submitted as part of an operator's EP, provided under existing SEMS regulations, or submitted as part of an operator's oil spill response plan. Some of the new information requested by BOEM is either outside the regulatory authority of BOEM or the agency's scope of expertise. This is acknowledged in the discussion of the IOP in the proposed rule, where the agencies explain, "the USCG administers laws and regulations governing maritime safety, security, and environmental protection and is also responsible for inspecting the vessels to which those laws and regulations apply." Nevertheless, while the proposed rule "acknowledge[es] the USCG's principal jurisdiction over vessel safety and security," it goes on to state that requesting duplicative information "early in the process . . . is also essential to DOI's statutory and regulatory responsibilities related to Arctic OCS oil and gas activities." This discussion fails to consider that BSEE or BOEM could obtain information in which it is interested from another agency that has jurisdiction over the matter of concern.

The Associations also object to the IOP for the reason that in many cases the information to be furnished in an IOP will be unobtainable based on the timeline the agencies proposed for submission of the document. BOEM has estimated that the submission of an IOP, including all required information will impose a time burden of only 90 hours per plan. BOEM notes that "[i]ndustry already compiles this information internally for planning and contract oversight; therefore, the burden expected is minimal, just to prepare and submit to BOEM." This statement is unsupported and inaccurate. While planning for exploration projects is a constant, the timing of availability of certain types of information can vary for many reasons. This factor alone could drastically increase the time burden estimated by BOEM by compelling an operator to compile this information to satisfy the particular timing of a compliance requirement as opposed to the requirements of a project and the sequence of decisions from a business or operational point of view. The preparation of an IOP for submittal could easily exceed the 90 hours of work estimated by BOEM, between compiling and drafting the plan for submittal and then (in all likelihood) having to respond to a large volume of requests for additional information from BOEM and other agencies. It is not clear how this additional compliance requirement would add value or provide information that the agency does not otherwise obtain through the EP or from other agencies.

If the IOP requirement remains intact in the final rule, The Associations urge BOEM to provide clarification as to the role and authority of the reviewing agencies identified in the proposed rule. In the preamble to the proposed rule, DOI notes that "[t]hrough BOEM would review the IOP to ensure that the operator's submission addresses each of the elements listed in § 550.204, the IOP would not require approval by DOI or the other relevant agencies. Instead, the IOP would be an informational document intended to facilitate early review of important concepts related to an operator's proposed exploratory drilling program." The Associations request that DOI clarify what the process is following submittal of an IOP under the proposed rule. Specifically, it should be clear whether an operator is obligated to respond to requests for additional information from BOEM, BSEE, or the other agencies DOI proposes to provide access to the document. If operators are obligated to respond to such requests, associated review timings should be established to ensure operators receive feedback within 45 days of submission. This would provide operators with the opportunity to review and, if needed, amend their EP before final submission. Furthermore, it should be clarified whether EP approval will be dependent upon the completion of all requests for additional information stemming from the IOP.

The Associations urge that the IOP requirement should be withdrawn.

5. The Associations Urge Adoption of Regulations That Accept Alternative Approaches to e to Loss of Well Control

The Associations recognize the interest of the agencies in assuring that operators in the Alaska OCS demonstrate that they would have access to, and could deploy, well control and containment resources that would be adequate to promptly respond to a loss of well control. In this area of unquestioned importance, The Associations urge the agencies to recognize that relief wells have historically not been used to regain well control, and, in terms of stopping the flow and securing the well as quickly as possible, they may not represent the best solution when compared to recent technological advances such as capping stacks and seabed isolation devices. For these reasons, The Associations urge the adoption of a more flexible regulatory approach that considers fit-for-purpose response planning alternatives to respond to loss of well control in the context of a given EP and the operating conditions it will be subject to.

a. Overview: The Need for Risk-Based Approaches to Well Control

Existing BSEE regulations (30 CFR § 250.141) provide that an operator “may use alternative procedures or equipment” after receiving approval from the appropriate Regional Supervisor,” if the proposed alternative “provide[s] a level of safety and environmental protection that equals or surpasses current BSEE requirements.” The proposed rule notes this existing regulatory provision and states that “operators may request approval of alternative compliance measures to the relief rig requirement in accordance with 30 CFR § 250.141.” See proposed 30 CFR § 250.472. This equivalency provision fails in several significant regards to address the issues created by the same season relief well proposal .

Firstly, the proposed rules fail to describe how an operator should demonstrate equivalency to a same season relief well, nor do they address the perceived risk reduction benefit, which is critical to establishing the baseline expectation. Secondly, and more fundamentally, the proposed rules fail to establish why a same season relief well should be a blanket requirement across all Arctic OCS MODU activities despite the range of risks to be considered and the numerous other available industry technologies and methods that have previously been utilized to successfully control wells.

b. The Associations Urge Action on the NPC Arctic Report’s Recommendation to Quantify the Risks and Benefits of Alternatives to a Requirement for a Same Season Relief Well

The additional human and environmental risk introduced into an operation by providing for a same season relief well on stand-by argues for careful consideration of alternative measures to address loss of well control. In the low probability event of a loss of containment event, “relief” would not come from a second well, but rather from a source control tool that could be swiftly deployed, such as a capping stack. In lieu of imposing a requirement for a relief well, which carries with it many of the same risks as drilling the exploration well. The Associations urge the agencies to act on the recommendation described in the NPC Arctic Report, that the industry and appropriate U.S. government agencies initiate a study to develop methodology to quantify the risks and benefits of multiple current barrier technologies, using appropriately detailed reliability data and assessments. The NPC Report further recommends that the results consider overall acceptability of risk levels, contribution of different risk mitigation practices, and justification of current practices on an as-low-as-reasonably-practicable basis, with comparison to other industries. The regulations should address separately, and in a performance-based manner, the objectives an operator must meet around source control versus a final kill of a well. Practices in assessment techniques from the nuclear, aviation, and petrochemical industries such as accident sequence precursor analysis are suggested for consideration. With a focus on spill prevention and barriers, such a study could be used as a basis to identify effective equivalent technologies for response to loss of well control in place of a requirement for a same season relief well. The time and ice/metocean conditions needed to enact these approved plans could then form the basis for determining an appropriate season end for primary drilling operations on a case-by-case basis.

Ultimately, BSEE’s proposed same season relief well requirement fails to follow longstanding executive guidance regarding effective and efficient performance-based regulations. Executive Order 13563, which

affirms and expands upon the regulatory principles established by Executive Order 12866, states that regulations should, "to the extent feasible, specify performance objectives, rather than specifying the behavior or manner of compliance that regulated entities must adopt." This preference for performance-based regulation was reinforced most recently in the recommendations put forth in the Presidential Commission Report to the President on Deepwater Horizon (2011), which stated: "The Department of the Interior should develop a proactive, risk-based performance approach specific to individual facilities, operations and environments, similar to the 'safety case' approach in the North Sea." Executive Order 13563 also mandates that agencies "consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the public where these approaches are relevant, feasible, and consistent with regulatory objectives." Given this express preference for performance-based regulations, BSEE should eliminate the same season relief well requirement and provide instead a requirement that an operator demonstrate in its plans that it has assets that can address a source control event. An operator should be permitted to select technology that is best suited to meet this objective within the confines of that operator's particular plan.

c. The Importance of Prevention, Achieved through Prudent Well Design

The NPC Arctic Report describes in detail industry's primary approach to loss of well control is prevention – achieved through adherence to established codes/standards and operations integrity management systems combined with a culture of safety and risk management. Wells can be safely drilled when designed for the range of risks anticipated, equipment has the required redundancy, personnel are trained, drills/tests are conducted, and established procedures are followed. The primary method to achieve prevention is through focus from the rig floor to the executive office on training, on operations consistent with training, and on prudent well design. Multiple spill prevention measures and barriers are currently designed into the wells drilled in the OCS, and these barriers are defined and specified in API/ISO standards and offshore regulations enforced by BSEE and BOEM. Drilling fluid, casing design, cement, and other well components are the primary barriers and the blowout preventers (multiple redundancies) are the secondary barrier to prevent a release to the external environment. This is the case whether a well is drilled in a temperate water or Arctic marine environment.

After the Macondo incident in 2010, OCS operators, BSEE, and API significantly upgraded regulations and standards with respect to well integrity and well control. Operators must follow a strict set of controls that require extensive verification, testing, and certification of well control equipment, well designs, and barriers to the flow of hydrocarbons. In U.S. federal waters, there is ample regulation to ensure operators and rig owners follow prudent practices. BSEE regularly sends inspectors to the drilling rigs to verify compliance. Furthermore through its Standards program, API has numerous documents that specify the equipment and procedures for well integrity and for rigorous drilling practices. In the highly unlikely event that all of the normal barriers fail during a drilling operation, the industry has also developed new subsea shut-in devices and capping stack technology that has substantially increased capability to secure a well from any uncontrolled flow of hydrocarbons.

d. The Role and Utility of Relief Wells

A relief well is a directional well drilled to communicate with a nearby uncontrolled (blowout) wellbore and control or stop the flow of reservoir fluids. If it is assumed that the original rig is disabled, a second rig would need to be mobilized and brought into proximity of the flowing well. The second rig would need to be equipped with casing, cement, drilling fluids, and wellhead equipment to construct the relief well. The distance between the blowout well and the relief well typically ranges between 500 feet and 3500 feet.

The Minerals Management Service published two papers³ on statistical data for blowout wells in the outer continental shelf of the U.S. These studies covered the 35 years from 1971 to 2006. These reports state,

³ Ezon, David, Danenberger, E.P., and Mayes, Melinda, "Absence of Fatalities in Blowouts Encouraging in MMS Study of OCS Incidents 1992-2006", Drilling Contractor magazine, pages 84-90, July/August 2007; Danenberger, E.P., "Outer Continental Shelf Drilling Blowouts, 1971-1991", OTC #7248, 25th Annual Offshore Technology Conference, Houston, Texas, May 1993.

“Although relief wells were initiated during several of the blowouts, all of the flowing wells were controlled by other means prior to completion of the relief wells.” The same situation occurred during the Macondo incident where well control was regained at the source through installation of a capping stack, not by drilling a relief well. Reliance on the false premise that relief wells provide a primary means of regaining well control would not only add substantially to already high drilling costs, it would also introduce risk by reducing the incentive or ability for an operator to use more effective alternatives appropriate to a given drilling program.

e. Well Control Response Technologies in the Arctic Operating Context

Among the reasons why the Associations and their members are very concerned about the imposition of a requirement for same season relief wells is the effect that such a requirement would have on the already short season for exploratory drilling in much of the Alaska OCS. An explanation of the basis of this concern is in order.

The technical ability to explore and develop in the offshore Arctic is governed by a number of key factors, including water depth, ice conditions, and the length of the open water season. Drilling rigs that rest on the seafloor have a maximum usable depth of about 100 meters in ice; deeper water requires floating rigs. Exploration can be carried out in waters with a short ice-free season using floating drilling rigs in waters deeper than about 20 meters, but development and production generally requires year-round operation to be economic, which means using facilities that rest on the seafloor and are resistant to ice forces in ice-prone areas.

Most of U.S. Arctic offshore resources are in less than 100 meters of water and have some open water season. As a result, exploration is possible during summer and shoulder seasons with floating drilling rigs, and development and production are technically possible using conventional bottom-founded drilling facilities with numerous support vessels including oil spill response vessels. Such technology has been field-proven in neighboring regions such as Canada where 39 offshore, incident free wells were drilled in pack ice conditions during the late 70's and 1980's.

Current regulations and permit conditions only allow exploratory drilling activity during the open water season. The U.S. Arctic open water season is typically only 3 to 4 months long and can be much shorter in a given year or be shortened by mid-season ice intrusions. The useful drilling period is further shortened by restrictions in recent permits requiring the ability to drill a same season relief well before the onset of ice. The useful drilling season may also be shortened as a result of voluntary agreements or regulations requiring an operator to cease operations to accommodate subsistence harvesting and marine mammal migration. It should also be recognized that the potential exists for the effective season length to be further reduced due to ice / metocean conditions that necessitate suspending active operations or in years of late melting / early freeze up.

The proposed regulations would make it difficult, and in many cases, impossible, to complete one well in a single season. Any cost-benefit analysis of this rule package should account for the erosion to an operator's portfolio caused by the lost drilling days attendant to a requirement for a same season relief well. The fewer days an operator has during the open-water season to explore its lease, the greater the number of its leases that will expire before they can be evaluated. The size and distribution of Arctic OCS resources are expected to require multiple wells to evaluate recoverable resource size and development concept and commerciality. Multiple expensive mobilizations over many years would therefore likely be necessary to complete exploration of a prospect, substantially reducing the economic feasibility of offshore Arctic development. This subject is discussed in additional detail in the NPC Arctic Report, where it is noted that the U.S. lease system is development based. In other words to retain a lease, the operator must have gained enough information to be able to move into the commercial development phase by the end of the 10-year primary term for an OCS lease. The short drilling season in the Arctic can make this determination practically impossible to achieve within the 10 year term when the drilling of several wells may be required to enable appraisal of a field. Other Arctic nations acknowledge this factor through longer lease terms, or by

providing an Operator the ability to retain a lease through the duration of exploration phase allowing extra time to determine technical or commercial viability (please see NPC Arctic Report Executive Summary at pages ES-25 through ES-26).

f. Primary and Secondary Barriers Described

In Arctic environments, The Associations believe it will be more effective from the standpoint of management of human and environmental risk in the Arctic offshore to focus on prevention and alternate methods than on a relief well plan. Prevention through prudent well design and operations should be the primary method for containment. Alternate methods such as capping stacks or subsea shut-off devices are a secondary method of spill mitigation and containment. A capping stack could be installed much more quickly than a relief rig could be deployed and put in operation (days instead of weeks), and a subsea shut-in device could be activated in minutes. Additionally, in certain situations supplemental subsea equipment could be used to increase the range of blowout preventer (BOP) functions to further increase capability to perform well control operations.

As noted in the NPC Arctic Report, the industry has made significant advances in being able to prevent, contain, and mitigate impacts of spills in Arctic environments. Prevention is maintained through a set of primary and secondary barriers.

The primary barriers maintain control against backward flow of formation fluids during the drilling process. These begin with well planning and design based on knowledge of the subsurface formations and fluid pressures gained from seismic exploration. Steel casing and wellheads are designed to withstand formation pressures, and specially formulated cement seals the steel casing to the borehole. The weight of the drilling fluid column is designed and monitored to offset subsurface formation pressures. Careful control of the drilling process is facilitated by having a crew of well-trained personnel who constantly monitor well stability. This includes the use of sensors located near the drill bit that continuously measure downhole conditions and transmit them to the drilling control room and surface measurements of the drilling fluid volume and flow rates, as well as geoscientists onsite who analyze the rock cuttings from the well.

Secondary barriers include procedures to detect and control deviations from normal operating conditions and the BOP. An example of a deviation is an influx of formation fluids into the wellbore, also called a "kick." Kicks are detected using equipment located on the deck of the drilling rig. If formation fluid flows into the wellbore, an increase in the volume of returning drilling fluid can be detected in the mud tanks and/or by gas detectors. A trained drilling crew will detect this and take the necessary action, which normally involves closing the BOP or pumping heavier mud into the wellbore.

The BOP has multiple, redundant, sealing components that can be remotely activated to close around or shear through pipe and seal the wellbore to provide containment of fluids in the event of a loss of well control. BSEE has numerous requirements for BOP tests. The BOP stack must be fully pressure tested every 14 days for subsea BOPs and every 21 days for surface BOPs, and a function test must be conducted every week. Also, the BOP stack must be pressure tested upon initial hook-up to the wellhead and after each casing string is set. Additional regulations implemented post-Macondo for BOPs include requirements to inspect for repair or remanufacturing at least every five years per the equipment owner's PM program and the manufacturer's guidelines. This maintenance may be performed on a staggered basis during the 5 year period. To ensure a broad range of BOP stack functionality, regulations require a minimum number of annular preventers, pipe rams and blind/shear rams, and additional redundancy such as two control stations, one located near the rig floor and the other distant from the rig floor.

Following loss of well control, other response measures are designed to limit the size of a spill once containment is lost and to respond to any spill. Flow-reduction measures are employed to decrease the rate of outflow by increasing the dynamic back-pressure applied by pumping through the BOP or other subsea devices. Flow-stoppage measures are employed to stop the outflow of a well to the environment through the use of shut-in devices such as a capping stack or a subsea isolation device at the seafloor whose operation is totally independent of the BOP. These tools are designed to stem any uncontrolled flow of oil as rapidly as

possible to minimize damage to the environment. The final available flow-stoppage measure is a relief well, which is a separate well drilled to intercept and permanently stop the flow from a blown-out well. In all cases to date, OCS subsea well control has been regained at the wellhead without the use of a relief well.

6. The Associations Urge that BSEE Not Grant Discretionary Authority to Restrict Discharge of Water-Based Muds and Cuttings that Have No Adverse Effect on the Environment

The U.S. Environmental Protection Agency, or a state environmental agency designated by EPA, not BSEE, regulates discharges of drilling muds and cuttings to state and federal waters of the U.S. Current National Pollutant Discharge Elimination System (NPDES) permits allow discharge of WBM and cuttings to federal, but not state, waters if they meet restrictions in the Effluent Limitation Guidelines (ELG).⁴

Proposed new section 250.300 would add provisions requiring the operator to capture all petroleum-based mud, and associated cuttings from operations that use petroleum-based mud, to prevent their discharge into the marine environment during exploratory drilling operations on the Arctic OCS. These provisions would also give the Regional Supervisors discretionary authority to require operators to also capture all water-based mud (WBM) and associated cuttings from Arctic OCS exploratory drilling operations (after completion of the hole for the conductor casing) to prevent their discharge into the marine environment based upon the Regional Supervisor's assessment of proximity to hunting and fishing grounds or what are described as showings of adverse effects on marine mammals, fish or their habitat. The Associations are concerned that incorporation of this language into the rule will establish an expectation that the Regional Supervisor will exercise his authority to restrict discharge of WBM and associated cuttings despite abundant evidence that such discharges have no significant impact on the marine environment.

a. Description of Water-Based Muds and Cuttings and Their Environmental Effects

WBM consist of fresh or salt water containing a weighting agent (usually barite; BaSO₄), clay or organic polymers, and various inorganic salts, inert solids, and organic additives to modify the physical properties of the mud so that it functions optimally. Drill cuttings are particles of crushed rock produced by the grinding action of the drill bit as it penetrates the earth.

The total mass of WBM and cuttings discharged per exploratory well is about 2000 metric tons/well, and somewhat less for most development wells. Assessment of the fate and effects of drilling discharges has shown that water column impacts are transient and limited in spatial extent. When WBM and cuttings are discharged to the ocean, the larger particles and flocculated solids, representing about 90 % of the mass of the mud solids, form a plume that settles quickly to the bottom. The spatial extent of any such settled cuttings and muds is dependent on the oceanographic conditions in the area. Typically though, these effects are limited to within hundreds of meters of the well site, and depending on the drilling mud type, usually the duration of measurable effect on the environment is measured in years, not decades. The remaining 10 % of the mass of the mud solids consisting of fine-grained unflocculated clay-sized particles and a portion of the soluble components of the mud form another plume in the upper water column that drifts with prevailing currents away from the platform and is diluted rapidly in the receiving waters. In well-mixed ocean waters, drilling muds and cuttings are diluted by 100-fold within 10 m of the discharge and by 1000-fold after a transport time of about 10 minutes at a distance of about 100 m from the platform. Because of the rapid dilution of the drilling mud and cuttings plume in the water column, harm to communities of water column plants and animals is unlikely and has never been demonstrated.

WBM and cuttings solids settle to and accumulate on the sea floor. If discharged at or near the sea surface, the mud and cuttings disperse in the water column over a wide area and settle as a thin layer of a large area of the sea floor. If mud and cuttings are shunted to and discharged just above the sea floor in order to protect

⁴ Neff, J. M. Fate and Effects of Water-Based Drilling Muds and Cuttings in Cold Water Environments. May 2010. Much of the discussion in this Section 6 is adapted or excerpted from this publication.

nearby sensitive marine habitats, the drilling solids may accumulate in a large, deep pile near the discharge pipe. Effects of WBM cuttings piles on bottom living biological communities are caused mainly by burial and low sediment oxygen concentrations caused by organic enrichment. Toxic effects, when they occur, probably are caused by sulfide and ammonia byproducts of organic enrichment. Recovery of benthic communities from burial and organic enrichment occurs by recruitment of new colonists from planktonic larvae and immigration from adjacent undisturbed sediments. Ecological recovery usually begins shortly after completion of drilling and often is well advanced within a year. Full recovery may be delayed until concentrations of biodegradable organic matter decrease through microbial biodegradation to the point where surface layers of sediment are oxygenated.

WBM are non-toxic or practically non-toxic to marine animals, unless they contain elevated concentrations of petroleum hydrocarbons, particularly diesel fuel. Most drilling mud ingredients are non-toxic or used in such small amounts in WBM that they do not contribute to its toxicity. Chrome and ferrochrome lignosulfonates are the most toxic of the major WBM ingredients. Although used frequently in the past in the Gulf of Mexico, these deflocculants are being replaced in most WBM by non-toxic alternatives to reduce the ecological risk of drilling discharges.

Many field monitoring studies, mostly in the U.S. Gulf of Mexico and the North Sea, have been performed since the 1970s to determine short- and long-term impacts of drilling discharges on the marine environment. As a general rule, effects of WBM and cuttings discharges on the bottom environment are related to the total mass of drilling solids discharged and the relative energy of the water column and benthic boundary layer at the discharge site. In high energy environments, little drilling waste accumulates on the sea floor and adverse effects of the discharges can not be detected. In low-energy environments or where mud and cuttings are shunted to near the sea floor, large amounts of mud and cuttings solids may accumulate on the sea floor and adversely affect bottom communities within a few hundred m of the discharge.

b. Water-Based Muds and Cuttings in Arctic and Cold Water Marine Environments

More than 50 exploratory wells were drilled in the State and Federal waters of the U.S. Beaufort Sea and Chukchi Sea between 1981 and 2002. The exploratory wells were in 18 to 167 feet of water. Drilling muds and cuttings were discharged from most of these wells directly to the water in the open-water season, or to the surface of the ice or under the ice in the shore-fast ice season. Ocean discharges of WBM and cuttings from several of the Beaufort Sea exploratory wells were monitored. The results of these studies were consistent with the conclusions of the 1983 National Research Council (NRC) report on drilling discharges in the marine environment: disturbance to the marine environment was minor and recovery was rapid.

The U.S., MMS, BSEE, and the oil industry have been monitoring the effects of drilling activities in the development area of the Alaskan Beaufort Sea for more than 20 years. The monitoring has shown that little metal, mostly barium, and petroleum hydrocarbons accumulate in sediments within a few hundred feet of gravel drilling islands and WBM and cuttings discharges. The increase over background concentrations of barium and occasionally other metals in sediments near drilling operations is insufficient to cause harm to local bottom-dwelling marine invertebrates. Since all these metals are tightly bound to solid particles (barite or clays), they are not bioavailable or toxic to bottom-dwelling marine organisms. Environmentally significant increases in the concentration of petroleum hydrocarbons, particularly polycyclic aromatic hydrocarbons (PAH) in Beaufort Sea sediments have not been detected. Similar results have been reported at drilling sites in the Dutch, United Kingdom and Norwegian North Sea where only WBM and cuttings were discharged.⁵

⁵ Neff, J. "Fate and Effects of Water Based Drilling Muds and Cuttings in Cold Water Environments". Duxbury MA, May 2010.

Prohibition of discharge of WBM and associated cuttings would achieve no ascertainable benefit to the marine environment and would impose unreasonable logistical challenges and costs on operators relating to the interim storage and later transport of these materials.

7. The Associations Urge Agencies Not to Introduce Regulations Incremental to the Existing Standards Established by the EPA for Cuttings Management in the Arctic OCS

Proposed new section 250.300 would add provisions requiring the operator to capture all petroleum-based mud, and associated cuttings from operations that use petroleum-based mud, to prevent their discharge into the marine environment during exploratory drilling operations on the Arctic OCS. The Clean Water Act grants EPA jurisdiction over all facilities which discharge pollutants from any point source into waters of the United States. This includes drill cuttings discharged from a rig into waters of the U.S. in Arctic regions. Under EPA regulations control is already established to ensure that when cuttings discharge is permitted the associated impact to the environment is reduced to acceptable levels. Introducing an additional and redundant layer of regulation by BSEE may not only be outside the scope of BSEE's authority but it will inevitably lead to confusion and conflicts.

In many situations the ability to discharge cuttings provides Operators the opportunity to demonstrate the net environmental benefits associated with offshore treatment and discharge versus alternative approaches. In addition, increased regulation of cuttings management without consideration of net environmental effects, i.e. blanket prohibition of non-aqueous fluids (NAF) cuttings discharge, could hinder Operators' ability to use the most effective mud system for the well and increase the likelihood of operational issues.

In operations where cuttings capture and transport is required, a number of additional critical path activities are introduced including incremental cuttings processing, container lifting/handling and vessel transfers. These activities are dependent not only on equipment uptime but also local metocean conditions and when processing capability is compromised drilling operations must be suspended or progressed at a reduced rate. These potential impacts to operations increase the likelihood of downhole issues which could lead to significant wellbore stability non-productive time (NPT) events. Such potential complications need to be carefully considered as part of any cuttings management system.

As a result of the overall complexity associated with both NAF and WBM cuttings management we urge BSEE and BOEM to recognize the authority of EPA to regulate discharge of drilling muds and cuttings, and to delegate this authority to the states. Instead of proposing redundant regulations, BSEE and BOEM should focus the proposed regulations on ensuring the current requirements are met during the well permitting and execution process. Such an approach will also allow industry to implement new and improved technologies that will further reduce the net environmental impact while further increasing overall operations integrity.

8. The Associations Urge Agencies Not to Require Tests of a Blow-Out Preventer at a Frequency That Would Risk Affecting Reliability and Integrity of Equipment

In new rule 250.447 BSEE proposes to revise paragraph (b) of this section to require a BOP pressure test frequency of one test every 7 days for Arctic OCS exploratory drilling operations. On this subject of the frequency of tests of BOP equipment and systems, The Associations urge BSEE not to increase the frequency of BOP testing from every 14 to every 7 days. Under current regulations, BOP functionality is already confirmed every 7 days via a full function test, (CFR 250.449 Paragraph h) in addition to the full pressure tests every 14 days. Based on the experience of testing of subsea BOPs in the Gulf of Mexico, generally followed by BSEE non-acceptance of reported anomalies reliable evidence exists that too frequent a cycle of testing does not improve BOP reliability and longevity, and the continuous testing and pulling for repair and additional testing of BOP's can be detrimental to their state of readiness and long term reliability. The data does not show that more testing is necessary or will increase reliability. Further there is

no technical basis that BOP's in the Arctic should have any difference in test frequency. BOPs are commonly used in the Arctic today – just not in Federal waters. The surface BOPs used in State waters and on land (and BOPs installed in GOM deepwater environments) are working in very cold conditions and have years of history of successful use and testing. Furthermore BOPs are often used in the normal course of drilling a well unrelated to well control and occasionally to circulate small well inflows. Thus BOPs are not just an emergency device and test frequency that could adversely affect their readiness and long term reliability are neither in the interest of operational safety nor environmental protection.

9. The Associations Urge Regulations That Support Flexibility in Oil Spill Response and That Accept Selection and Execution of Strategies That Are Most Effective Given the Circumstances of a Spill

On the matter of prevention, preparedness and assurance of a capability of response to oil spills from drilling and production operations in the Alaska OCS, The Associations believe that both regulation and operations must be informed by the following:

- The role of prevention as the primary defense against loss of well control
- Recent technical advances in source control
- The long history of research into oil behavior and spill response in ice
- Flexibility to select and execute the most effective strategy or strategies in context with the situation in the event response to a spill is required

The greatest reduction of environmental risk comes from preventing any loss of well control. This is achieved through adherence to established codes/standards and operations integrity management systems, combined with a culture of safety and risk management. Industry's primary approach to prevention is guarding against loss of well control. A major well-control event is extremely unlikely, and recently upgraded U.S. regulations, standards, and practices make the likelihood of a major well control event even less likely. Recent steps taken to improve safety include certification by a licensed professional engineer that there are two independently tested barriers across each flow path and that the casing design and cementing design are appropriate and independent third-party verification of the BOP. These engineering safeguards are backed up by requiring strict adherence to operations integrity management systems as part of an overall culture of safety and risk management. The multiple spill prevention measures and barriers that are designed into the wells are defined and specified in U.S. and international standards and U.S. offshore regulations. Arctic well design and construction follows these standard offshore well practices.

Additional well control devices and techniques are now available that are independent of the controls on the drilling rig. Examples of these devices are capping stacks that are deployed after an incident to stop the flow from the well and subsea isolation devices installed before the well encounters potential hydrocarbon-bearing zones in addition to standard BOP. These systems offer a dramatic reduction in worst-case discharge volumes because they are designed to stop the flow of oil in a matter of minutes, hours, or days versus weeks or months. Consequently, they can provide a superior alternative for quickly stopping the flow, minimizing the spilled volume of hydrocarbons and securing the well than that offered by the requirement for same season relief well and/or oil spill containment systems.

Over the past four decades, the oil industry and government have made significant advances in being able to detect, contain, and clean up spills in Arctic environments. Many of these advances were achieved through collaborative international research programs with a mix of industry, academia, and government partners. Much of the existing knowledge base in the area of Arctic spill response draws on a long history of experiences with a number of key field experiments, backed up by laboratory and basin studies in the United States, Canada, Norway, and the Baltic countries.

a. Advances in Research and in Lessons Learned

The ongoing Arctic Oil Spill Response Technology Joint Industry Programme (ART JIP) is a comprehensive research initiative bringing together the world's leading Arctic scientists and engineers. This program was initiated in 2012 as a collaboration of nine international oil and gas companies: BP, Chevron, ConocoPhillips, Eni, ExxonMobil, North Caspian Operating Company, Shell, Statoil, and Total. These companies have come together to further enhance industry knowledge and capabilities in the area of Arctic spill response as well as to increase understanding of potential impacts of oil on the Arctic marine environment. Such collaborative projects, in a noncompetitive technology arena wherein all stakeholders stand to gain from mutual advancement of capabilities, have been the hallmark of industry's oil spill response research.

In addition to substantial industry-sponsored research, there has been a long and effective research effort led by government organizations. For more than three decades, MMS/BSEE has funded programs for open water and in ice. The National Oceanic and Atmospheric Administration (NOAA) is involved in a variety of oil spill research projects in conjunction with academia and other agencies that includes development of an Arctic version of its oil spill trajectory model GNOME (General NOAA Operational Modeling Environment). The U.S. Environmental Protection Agency is conducting tests of dispersant efficacy and toxicity at low temperatures.

There is extensive knowledge on oil spill response and behavior in ice and cold water based on at least four decades of research. Industry and government agencies continue to put significant resources into technology enhancements through collaborative research that will further improve the operability and effectiveness of different response systems in ice. Defining and gaining acceptance of existing technology and technology enhancements requires integrating a diverse set of stakeholder groups, including Arctic community residents and regulators, into a collaborative effort to resolve uncertainties and agree in advance on the most effective oil spill response options for a given drilling program.

In addition, The Associations object to BSEE's proposal to combine oil spill response planning with plans relating to source control and containment equipment (SCCE). The information sought in proposed §250.70 is best maintained in a separate plan for the SCCE equipment such as the capping stack, cap and flow system, containment dome, and other similar subsea and surface devices. The Oil Spill Response Plan (OSRP) may include a reference to the separate SCCE plan dealing with the capping stack, cap and flow system, etc., but the OSRP is already a large plan that is utilized and well understood by oil spill responders. BSEE's proposal that the two plans be combined will inject confusion for personnel executing the OSRP, creating an unacceptable safety risk.

b. The Importance of the Full Tool Kit of Oil Spill Response Alternatives

The overall goal of spill response is to control the source as quickly as possible, minimize the potential damage caused by an accidental release, and employ the most effective response tools for the incident. Promoting mutual understanding of the benefits, limitations, and trade-offs of different response tools would facilitate achieving this goal. Response options that are highly effective under certain conditions may be ineffective in others depending on spill size, location, oil type/weathering, and environmental conditions.

The Associations strongly encourage development of an educated and more balanced perspective regarding the full range of available response techniques, including controlled burning and the application of chemical dispersants. The response community and the general public must be informed of the benefits, limitations and tradeoffs associated with these techniques, and be provided the information to understand that even under the best of conditions, one can never expect to recover or eliminate all of the oil spilled. The Associations also support development of Federal and state planning standards and regulations that address realistic operational and environmental constraints, as well as practical levels of response capability. The type and number of resources that can be maintained and operated safely and effectively for a given area, project, or facility should reflect a careful assessment of the most probable spill events that might occur,

while recognizing that backup resources can be cascaded within a short period of time to support a more serious spill event.

Technology enhancements will continue to improve the operability and effectiveness of different response systems in ice. There nevertheless remains an ongoing challenge to share information on spill response capabilities in Arctic conditions with a diverse set of stakeholder groups, residents and regulators to gain acceptance that all response options, including burning and dispersants, need to be available for responders to use on short notice as the spill behavior and environmental conditions dictate. Ultimately, decisions to employ a particular strategy need to be contingent on demonstrating a positive net environmental benefit.

10. The Associations Urge BSEE to Leave Key Operational Decision making in the Hands of Individual Operators to Maximize Operations Integrity

A consistent theme noted in the proposed regulations is for BSEE to take an increased role in day to day operations and critical decision making processes. Some specific examples include:

- 250.188 regarding immediate oral reporting of *even potential* ice management activities
- 250.452 regarding real time monitoring requirements, onshore command centers and BSEE access
- 250.471(h) You must deploy and use SCCE when directed by the Regional Supervisor
- 250.472 "... the Regional Supervisor may direct you to drill a relief well...."
- 254.90 (c) "... the Regional Supervisor may direct you to deploy and operate your spill response equipment and/or your capping..... as part of announced or unannounced exercises...."

Shifting operational decision making away from Operators and their rig site personnel exposes the operations to increased risk levels. During any given operation the onsite personnel have the best understanding and most complete picture of the current operation, key risks and critical considerations. In addition, their experience in active operations provides them with the judgment to make effective real-time decisions within the bounds specified by the Operators governing procedures and operations integrity guidelines. This responsibility includes full control of the operations and the full authority to stop activities at any time.

As a general rule, Operators that use shore-based operations centers do so to assist personnel on the rig with monitoring of specific functions of the drilling operation, not to assume control of operational activities. Furthermore, Operators should have the flexibility to develop a performance-based approach (rather than follow a prescriptive requirement) described in their EP or Authorization for Permission to Drill (APD) describing what functions of these systems will be monitored in the wells(s), which will vary with the rig used and the equipment on board the rig, as well as the location of any support facilities ashore. It should be clear to BSEE that it remains the primary responsibility of the rig personnel to monitor information from drilling operations on a 24/7 basis and to take appropriate actions without waiting for direction from a remote shore base. Utilizing real-time data centers and shorebase decisionmaking may lead to a decrease in offshore personnel's responsibility and accountability which is critical to maintaining safe operations and responding to emergency situations. In times of communication interruptions or significant offshore events (well control, station keeping difficulties, vessel collisions, equipment failure, etc) there is generally insufficient time to interact with shorebase command centers to plan a response. It is these critical moments that offshore supervision is key and its effectiveness can only be maintained if the primary decisionmaking remain focused at location. To ensure offshore personnel are equipped with the necessary knowledge prior to specific operations, a range of preparatory engagements are held with the shorebase engineering and operations support teams or through on-site engineering assistance. In these engagements, the key risks and critical steps are discussed to prepare the offshore team for the upcoming operations, including discussion of potential risks and appropriate responses. This approach should be maintained for all active drilling operations.

In situations where an escalation of response is required, such as mobilizing Source Control and Containment Equipment or commencing relief well operations, the Operator is in the best position to select the appropriate next steps due to their understanding of the overall operational situation and available resources. In obtaining permits for Arctic operations the Operator will be required to submit a number of documents to address how they intend on responding to a variety of emergency scenarios. These documents provide BSEE and other regulatory bodies the ability to direct the ultimate response to ensure the necessary SSH&E standards are met while leaving the actual implementation to the expertise of the Operator and their identified sub-contractors.

The proposed BSEE rules seek to incorporate a number of reporting requirements associated with ice monitoring that due to the dynamic and variable nature of ice movements in the Arctic will likely result in frequent interactions with BSEE. Each offshore Arctic drill site has unique ice and metocean conditions, and the rigs selected to drill will vary in their ability to interact with ice and maintain operations in those environments. For effective interactions on ice monitoring and management, BSEE would need to be fully engaged in and familiar with the particular ice management procedure for the well, risk assessments, training and execution preparations in order to be prepared to fully engage. To meet the intent of the proposed rule it is recommended that the requirement focus on the need for Operators to specify in advance the reporting requirements based on the assessed risks associated with the specific well and location. These guidelines could be incorporated into Operator's Ice Management Plan which would be reviewed and approved as part of the regulatory permitting process.

The proposed BSEE rules require reporting of kicks or unplanned events that could compromise well control. It is critical that regulations seek to maintain focus on prevention and, if necessary, responding to the situation on site. Requirements for immediate oral reporting to BSEE outlined in the proposed rules is vague and needs to be clarified. Immediate engagement with BSEE will be of limited value as the overall situation assessment will still be underway. In the circumstances described in this provision, the operator's sole focus should be on making conditions safe at the well site, yet this provision seems to take the focus away from operators taking the actions necessary to ensure safety, instead putting an emphasis on immediate engagement with the regulator through reporting. As the Operator will be responsible for immediate response, it is recommended that no additional reporting regulations are adopted incremental to the existing OCS requirements.

Furthermore, BSEE's stated desire for immediate reporting implies that the agency believes that kick control is the responsibility of the regulator. The Associations request clarification that BSEE is not suggesting that the agency is going to direct well control activities beginning with any unexpected kick. There are circumstances, when drilling into a formation that a change of pressure is predicted, or a thin small zone that is charged, that a kick could be taken and it would be considered a normal part of the exploration drilling activity, but under the language used in the proposed regulation could be considered a "potential well control incident". Premature regulator intervention would increase confusion and any existing risks pertaining to the status of the well under such circumstances. Inclusion of information about kick occurrences in existing regularly submitted well activity reports (daily and weekly) will fully satisfy the need for the regulator to have better information.

With respect to proposed §254.90 (c), if adopted, this section must acknowledge the jurisdiction of the U.S. Coast Guard over marine oil spill response preparedness and operations, as well as well containment operations that may be carried out in connection with response to a spill. Under the National Contingency Plan, in the event of a spill from an offshore drilling operation, federal on-scene command established for any such incident will be led by a representative of the U.S. Coast Guard.

Additionally, The Associations request that BSEE remove the annual auditing requirements set forth in proposed §250.1920(b)(5). BSEE has not provided any justification for this increased frequency which will not have an effect on safety or compliance since the SEMS program does not change on an annual basis. Existing BSEE regulations require an audit of the SEMS program on a three-year cycle which has worked

effectively for operations in the Gulf of Mexico and should be more than adequate for operations in the Alaska OCS.

With all decisions related to active offshore operations there is a certain level of risk, responsibility and accountability. In the event BSEE seeks to direct active drilling operations, further clarification is required on the associated responsibility, accountability and liability that would be assumed in the event of any incidents that occur as a direct result of those actions. It is for these reasons we urge BSEE to leave key operational decisionmaking in the hands of the Operators and focus the regulations on ensuring that drilling plans and operations are risk based, and fit for purpose for every proposed location.

11. The Associations Urge Delaying the Release of the Proposed Arctic Rules until the Recently Proposed BOP and Well Control Rules Have been Finalized

On April 13, 2015, proposed new rules were issued by BSEE for all OCS areas that are focus on Blowout Preventer Systems and Well Control. The proposed rules significantly alter the current regulations in both content and structure and overlap in numerous areas with the proposed Arctic OCS rules. The heightened requirements that will result with the final publication of the BOP and Well Control rules will impact considerations for the Arctic OCS rules. Because of this, The Associations request that the comment period of the Arctic OCS rules be re-opened after the BOP and Well Control final rules are published. This will ensure all parties fully understand the base regulatory regime for OCS areas and enable more informed decisions to be made regarding incremental Arctic OCS requirements.

Thank you for considering these comments. If you have any questions, please do not hesitate to contact the undersigned.

Very truly yours,



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The CHAIRMAN. Thank you, Mr. Milito. Dr. Rockel, welcome.

**STATEMENT OF DR. MARK ROCKEL, PRINCIPAL CONSULTANT,
RAMBOLL ENVIRON**

Dr. ROCKEL. Good morning, Chairman Murkowski, Ranking Member Cantwell, and members of the Senate Energy and Natural Resources Committee.

My name is Mark Rockel. I am Principal Consultant for Ramboll Environ, and I have over 30 years of experience in natural resource economics.

Ramboll Environ has prepared an analysis to inform OMB's review of regulations promulgated by Department of the Interior governing oil and gas exploration activities in the Alaska Outer Continental Shelf. Included is a benefit-cost analysis of three elements that may be included in these regulations.

The same-season relief rig is a requirement that would direct all Arctic operators to contract a second rig capable of drilling a relief well prior to the onset of winter ice. Over a 20-year exploration and appraisal phase, the present value of an SSRR requirement is nearly \$3.2 billion in cost to the lessee. In contrast, the benefits of this requirement over the same time period has been estimated at only \$791 million.

The relatively minor benefits associated with a same-season relief rig requirement are due in part to the low probability of a well blowout in the shallow exploration and appraisal wells of the U.S. Arctic Outer Continental Shelf. There is a hierarchy of barrier and control technologies and responses that, depending on the situation, could provide not only a faster, more environmentally protective response than a relief well, but one that is more cost-efficient. The availability and use of other technologies to stop a loss of well control is reinforced by U.S. Government records. Since 1971, there has not been a single blowout event in the U.S. controlled by a relief well.

The relative costs and benefits of a same-season relief rig requirement cannot be supported. Further, the modest benefits of such a requirement could be preserved and potentially exceeded given advancing technologies if the United States adopted a performance standard calling for same-season relief rig equivalency.

For season drilling limitations requires that an Arctic operator cease drilling into hydrocarbons at a prescribed date based on the anticipated onset of winter ice. Over a 20-year exploration and appraisal phase, the present value of such a seasonal limitation requirement is \$6.8 billion in cost to the lessee. In contrast, the benefits are estimated at \$301 million over the same period.

The rationale underlying the seasonal direction limitation is that it is necessary to ensure that an operator has time to use the single-season—the same-season relief rig to drill a relief well prior to the onset of winter ice. Yet drilling a relief well is not the only method or most efficient method an operator could use to control a late-season blowout. Even where the assumption is made that a relief well is the only or preferred response, the benefits gained from imposing a blackout window are minimal.

Regulations already require that an operator submit a Critical Operations Curtailment Plan or as part of the Exploration Plan to

demonstrate that it has a plan to curtail operations in response to emerging hazards in the environment.

Further, in other areas where BOEM regulates offshore oil and gas activities, including the Gulf of Mexico, the agency does not regulate prescribed end-of-season dates based on seasonally reoccurring environmental threats such as hurricanes.

Whether and if an operator is required to end his drilling season should be driven by whether the assets the operator is bringing to the theater are capable of safely drilling for the period of activity the operator has planned.

And finally, for 100 percent mechanical recovery capacity, that requires an operator maintain mechanical assets sufficient to account for 100 percent recovery of a worst-case discharge. The cost of this requirement over a 20-year exploration and appraisal phase is \$119 million to the lessees, but there are no appreciable environmental and social benefits attributed to this if you compare it with an approach that has been used throughout the world, a net environmental benefits analysis. And this approach is applied to all United States Outer Continental Shelf regions and around the world.

Requiring an operator to maintain 100 percent mechanical assets is inefficient and may result in additional impacts to the environment from having more vessels at sea. The impacts cannot be justified considering that in the event of an actual oil spill an emergency response team may determine the best option for responding is not with mechanical recovery tools but also with other tools in the toolbox such as in situ burning and dispersants. Any Arctic regulations dealing with oil response should allow the operators and the people on scene to apply a net environmental benefits analysis approach and account for all appropriate response tools.

If codified in a regulation, these elements would be inconsistent with U.S. policy guidance directing agencies toward performance-based regulations and would not be in harmony with international standards and best practices. Denmark, Canada and Greenland have all adopted elements of performance-based regulation for drilling requirements, well control, and independent verification and oil response.

Thank you for allowing me the opportunity to testify today.

[The prepared statement of Dr. Rockel follows:]

WRITTEN TESTIMONY OF MARK ROCKEL, Ph.D.
PRINCIPAL CONSULTANT
RAMBOLL ENVIRON
BEFORE
THE SENATE ENERGY AND NATURAL RESOURCES COMMITTEE
HEARING TO RECEIVE TESTIMONY ON THE WELL CONTROL RULE AND OTHER REGULATIONS RELATED TO
OFFSHORE OIL AND GAS PRODUCTION
DECEMBER 1, 2015

Good morning Chairman Murkowski, Ranking Member Cantwell, and members of the Senate Energy and Natural Resources Committee. My name is Mark Rockel. I am a Principal Consultant from Ramboll Environ and have over 30 years of experience in natural resource economics within the academic, government, trade group, and consulting arenas.

The Office of Information and Regulatory Affairs (OIRA), a division of the Office of Management of Budget (OMB) is tasked with the review of new rules promulgated by regulatory agencies. A series of executive orders has dictated that the benefits of new regulations not be outweighed by the costs of compliance, and not ultimately serve to stifle innovation, creativity or the efficient function of markets. It is through this lens that the OIRA reviews an agency's regulatory impact assessment (RIA) of its own proposed rules to ensure that draft regulations align with the presidential directives set forth in these executive orders. Ramboll Environ had prepared an analysis to inform the OIRA's review of regulations promulgated by the Department of Interior (DOI) governing oil and gas exploration activities in the Alaska OCS (Arctic Regulations). Included is a benefit-cost analysis (BCA) of three elements that may be included in the draft Arctic Regulations: (1) a same season relief rig (SSRR) requirement; (2) a seasonal limitation on drilling; and (3) a requirement that an operator demonstrate capacity to respond to 100 percent of its Worst Case Discharge (WCD) with mechanical recovery tools alone.

The results of this analysis illustrate a substantial disconnect between these rule elements and the presidential directives outlined above. The OIRA should apply its authority under Executive Order 12866 to return the draft Arctic Regulations to the DOI if any of the three elements analyzed are present in the actual rule.

Same Season Relief Rig

An SSRR requirement would direct all Arctic operators to contract a second rig capable of drilling a relief well and maintain that rig in proximity to the theater such that the rig would be available to drill a relief well prior to the onset of winter ice. Over a twenty-year exploration and appraisal phase, the present value of a SSRR requirement is nearly 3.2 billion dollars in cost to the lessee. In contrast, the benefits of a SSRR requirement over the same time period are estimated at only 791 million dollars. The relatively minor benefits associated with a SSRR requirement are due in part to the low probability of a well blowout in the shallow exploration and appraisal wells being pursued in the U.S. Arctic OCS.

The nominal benefits associated with a SSRR requirement can also be explained by the substantial barrier and control technologies that operators have in place both to mitigate the risk of a loss of well control, as well as to respond if such an event occurs. There is a hierarchy of technologies and responses that, depending on the situation, could provide not only a faster, more environmentally protective response than a relief well, but one that is more cost efficient. The availability and use of other

technologies to stop a loss of well control is reinforced by U.S. government records; since 1971 there has not been a single blowout event in the U.S. controlled by a relief well.

Given the relative costs and benefits of a SSRR requirement, the codification of such a requirement cannot be supported. Further, the modest benefits from such a requirement could be preserved (and potentially exceeded given advancing technologies) if the U.S. adopted a performance standard calling for SSRR equivalency.

Seasonal Drilling Limitation

A seasonal drilling limitation refers to the requirement that an Arctic operator cease drilling into hydrocarbons at a prescribed date calculated based on the anticipated onset of winter ice. Over a twenty-year exploration and appraisal phase, the present value of such a seasonal limitation requirement is 6.8 billion dollars in cost to the lessee. Such a condition also results in losses to the nation in the amount of 89 billion dollars. In contrast, the benefits of a seasonal drilling limitation are estimated at 301 million dollars over the same period. The rationale underlying the seasonal drilling limitation is that it is necessary to ensure that an operator has time to use a SSRR to drill a relief well prior to the onset of winter ice. Yet, as discussed in the preceding section, drilling a relief well is not the only method, or most efficient method an operator could use to control a late season blowout. However, even where the assumption is made that a relief well is the only (or preferred) response, the benefits gained from imposing a blackout window are minimal. Regulations already require that an operator submit a Critical Operations Curtailment Plan (COCP) as a part of its Exploration Plan (EP) to demonstrate that it has a plan to curtail operations in response to emerging hazards in the environment. Further, in other areas where the BOEM regulates offshore oil and gas activities, including the Gulf of Mexico, the agency does not regulate prescribed end of season dates based on seasonally re-occurring environmental threats, such as hurricanes. Given the relative costs and benefits of a seasonal drilling limitation, the codification of seasonal drilling limitations cannot be supported. Whether and if an operator is required to end its drilling season should be driven by whether the assets the operator is bringing to the theater are capable of safely drilling for the period of activity the operator has planned.

100% Mechanical Recovery Capacity

A 100 percent mechanical recovery capacity requirement refers to the requirement that an operator demonstrate in its Oil Spill Response Plan (OSRP) that it has mechanical recovery assets available to respond to its entire Worst Case Discharge using those assets alone, as opposed to other tools such as In Situ Burning (ISB) or dispersants. Currently, operators in the Chukchi and Beaufort Seas are required to meet this requirement due to the North Slope Subarea Contingency Plan, which is a part of the Alaska Federal/State Preparedness Plan for Response to Oil & Hazardous Substance Discharges/Releases. The cost of this requirement over a twenty-year exploration and appraisal phase is 119 million dollars to lessees. There are no environmental or social benefits attributable to this requirement if you compare it with an approach that allows an operator to develop its OSRP using the Net Environmental Benefits Analysis (NEBA) approach that is applied in other U.S. OCS regions and around the world. Requiring an operator to maintain mechanical assets sufficient to account for 100 percent recovery of its WCD in proximity to the drill site is inefficient and may result in additional impacts to the environment. This requirement significantly increases the number of vessels an operator must maintain in theater to support its drilling activities. With additional vessels comes the potential for additional environmental impacts. These impacts cannot be justified considering that in the event of an actual oil spill an emergency response team may determine the best option for responding is not with mechanical

recovery tools, but with ISB or dispersants. Depending on spill characteristics and metocean conditions, dispersants and ISB are more effective at cleaning up an oil spill than is mechanical recovery equipment. Given the relative costs and benefits of a 100 percent mechanical recovery capacity requirement, the codification of such a requirement cannot be supported. Any Arctic Regulations dealing with oil spill response should allow operators to apply a NEBA approach and account for all appropriate response tools.

Conclusion

The proposed rule elements are not performance based, even where obvious performance based approaches are available and would achieve the desired objectives. This analysis has demonstrated that allowing for SSRR equivalency, performance based season limitations, and strengthening the dependence on the NEBA approach may be less costly, and more effective regulatory approaches that respond to the call for performance based regulatory approaches found in Executive Order 12866. The conclusion of the review is that the costs of the potential elements reviewed significantly exceed their benefits. In addition, if codified in a regulation, these elements would be inconsistent with U.S. policy guidance directing agencies toward performance based regulations and would not be in harmony with international standards and best practices. Denmark, Canada, and Greenland have all adopted elements of performance-based regulation for drilling requirements, well control, and independent verification and oil spill response.

Performance-based regulation is outcome driven. The regulator sets goals and objectives to be achieved and allows room for a variety of avenues to compliance, rather than prescribing methods, practices, or technologies that must be used to achieve a goal or objective. Performance-based regulation tends not to constrain markets or technological innovation, but rather provides incentives for market mechanisms to spur technological advances, bringing about operational and environmental improvements efficiently as companies strive to compete.

Thank you for allowing me the opportunity to testify today.

The CHAIRMAN. Thank you, Dr. Rockel.
Ms. Savitz, welcome.

**STATEMENT OF JACQUELINE SAVITZ, VICE PRESIDENT, U.S.
OCEANS, OCEANA**

Ms. SAVITZ. Thank you. Good morning, Chairman Murkowski, Ranking Member Cantwell, and members of the committee. Thank you for the opportunity to testify today.

My name is Jackie Savitz and I am Vice President for U.S. Oceans at Oceana, the largest international advocacy organization that is focused exclusively on ocean conservation.

Oceana regards offshore drilling as a dangerous practice that places our marine ecosystems at risk and threatens the coastal economies that depend on healthy oceans for fishing, tourism, and recreation. We therefore oppose the expansion of offshore drilling into the Arctic and Atlantic Oceans, and we advocate for a transition away from fossil fuels and toward clean energy to avoid the worst impacts of climate change. Doing so will also reduce pollution, increase energy security, and create job security.

We realize that the U.S. will not stop offshore drilling overnight, so we applaud the efforts of BSEE to increase drilling safety. While the proposed rule is not robust enough to protect the oceans, it is a significant improvement over the status quo and addresses many of the concerns raised by the commissions that investigated the Deepwater Horizon tragedy.

We therefore urge the Administration to finalize and implement this rule as expeditiously as possible. Our interest in this rule stems from our concern about the damage to ocean ecosystems and human communities that depend on them. Oil and gas are toxic to fish, shellfish, marine mammals, birds, sea turtles, and corals, virtually every part of the marine food web.

The BP oil spill in the Gulf of Mexico killed an estimated 5,000 marine mammals and nearly a million coastal and offshore birds. More than 1,000 sea turtles were found dead, and at least three deep-sea coral communities were extensively damaged. Some of those losses had direct impacts on Gulf Coast communities, harvest of oysters and fish were reduced devastating the Gulf's fishing communities and tourists fled the region. In fact, tourism suffered even in parts of the Florida coast where no oil even washed ashore.

Nearly six years have passed since the BP disaster. It is deeply concerning that there has been no legislation and few regulatory changes to improve well control or the dependability of blowout preventers in all that time.

In just four years following the Deepwater Horizon, BSEE reported that offshore drilling caused more than 1,000 injuries, more than 400 fires and explosions, more than 20 losses of well control, 11 spills, and 11 more fatalities. Given this perilous operational backdrop, BSEE should quickly finalize and implement the rule.

We would, however, urge BSEE to make some improvements. They should require companies to deploy two shear rams that are capable of sealing the well bore on all blowout preventers. Requiring the installation of two blind shear rams would add redundancy to the system so that if one blind shear ram failed to sever the pipe, the second one might be able to do so. On the Deepwater Ho-

rizon, one set of blind shear rams failed to complete a seal because a portion of drill pipe was knocked out of alignment in the explosion, and this led to the release of catastrophic amounts of oil and natural gas.

And the problem is pervasive. West Engineering Services, an industry safety specialist, found that only three of the seven blowout preventers successfully sheared pipe in realistic emergency conditions.

Oceana is concerned that the compliance periods proposed in the rule will cause unnecessary and potentially harmful delays, especially considering that the rule comes out more than five years after the Deepwater Horizon disaster. BSEE compounds this delay by introducing a potential three- to seven-year compliance period for critical aspects of the rule, including the installation of two shear rams.

BSEE is also considering the inclusion of a ten-year compliance period for companies to install important technology that is capable of severing components of the drill string. In all, it could be more than 16 years after the Deepwater Horizon catastrophe before BSEE finalizes and the industry implements these critical safety regulations, 16 years. This timeline is not acceptable.

Further, two systemic problems remain that make the risk of loss of well control unacceptably high. These include the inadequate fines that incentivize rule-breaking and risk-taking and the abysmal inspection rates. Both are discussed in more detail in our written testimony.

In conclusion, we commend BSEE for the safety improvements proposed in the well control rule and urge the agency to strengthen it by requiring redundant blind shear rams and reducing compliance periods and to promulgate the final rule as soon as possible.

Even with these recommendations adopted, offshore drilling will continue to pose a grave threat to lives and livelihoods, as well as marine ecosystems. We saw in 2010 that offshore drilling can be life-threatening to workers, harmful to ocean ecosystems, and destructive to the human communities that depend on them. But it appears we did not learn. We therefore recommend that Congress and the Administration do not allow the expansion of offshore drilling into the Atlantic and Arctic Oceans. The only sure way to prevent the harm caused by offshore spills is to decrease our dependence on fossil fuels and transition to clean, sustainable renewable energy sources like offshore wind power.

This concludes my statement. I look forward to your questions and further discussion.

[The prepared statement of Ms. Savitz follows:]

Testimony of Jacqueline Savitz
Vice President, U.S. Oceans
Oceana
Hearing on the Well Control Rule
U.S. Senate Committee on Energy and Natural Resources
December 1, 2015

INTRODUCTION

Good morning, Chairman Murkowski, Ranking Member Cantwell, and members of the Energy and Natural Resources Committee. Thank you for the opportunity to testify before you today about the proposed rule on “Oil and Gas and Sulphur Operations in the Outer Continental Shelf – Blowout Preventer Systems and Well Control,” also known as the “Well Control Rule.” My name is Jacqueline Savitz, and I am Vice President for U.S. Oceans at Oceana, the largest international advocacy organization focused exclusively on ocean conservation.

In April 2015, the Department of the Interior’s Bureau of Safety and Environmental Enforcement (BSEE) proposed new regulations to protect human lives and the environment from the threat of well blowouts. This proposed rule includes more stringent design requirements and operational procedures for critical well control equipment used in offshore oil and gas operations.^{i,ii} Many of these actions relate to the maintenance, design, and certification of blowout preventers.

Oceana applauds the efforts of BSEE and the Department of the Interior to increase the safety of offshore drilling operations; however, the proposed rule in its current form is not sufficiently robust to protect the oceans. That being said, the proposed rule is a significant improvement over the status quo and addresses many blowout-related concerns raised by various commissions following the BP tragedy in 2010. Oceana therefore urges BSEE and the Department of the Interior to finalize and implement this rule as expeditiously as possible.

NEED FOR STRONGER PROTECTIONS

Oceana’s interest in this rule stems from our concern about the damage to ocean ecosystems, and to the human communities that depend upon them, that can result from leaks and spills of oil and gas and associated materials into the ocean. Oil and gas are toxic to fish, shellfish, marine mammals, birds, sea turtles, corals, and virtually every part of the web of life in the ocean. It is estimated that the catastrophic BP oil spill in the Gulf of Mexico killed as many as 5,000 marine mammals and nearly one million coastal and offshore birds. More than 1,000 sea turtles were found dead, and three deep-sea coral communities were extensively damaged. Harvests of oysters and fish were drastically reduced, devastating the Gulf’s fishing communities, and tourists fled the region.ⁱⁱⁱ In fact, tourism suffered even in vacation destinations along the Florida Gulf Coast where no oil washed ashore.^{iv}

Rather than expanding offshore oil drilling, the U.S. should transition away from it, and replace it with offshore wind power and other types of clean, renewable energy. In a recent report on offshore energy, Oceana found that a modest and gradual development of offshore wind on the East Coast could generate enough power for over 115 million households. We also found that over the next 20 years, offshore wind could create about 91,000 more jobs than offshore drilling, which is about double the job creation potential of offshore drilling in the same area.^v

With dozens of offshore oil rigs currently operating in U.S. waters,^{vi,vii} we take a strong interest in the Well Control Rule. As Secretary Jewell acknowledged when she unveiled it, the proposed Well Control Rule builds on multiple investigations of the Deepwater Horizon disaster,^{viii} including the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, found numerous errors, mistakes and management failures that compromised safety^{ix} and resulted in one of the worst environmental disasters in US history. The National Commission's investigation also found that equipment and practices had failed to keep pace with the challenges as the industry moved into deeper water:

...drilling in deepwater brings new risks...The drilling rigs themselves bristle with potentially dangerous machinery. The deepwater environment is cold, dark, distant, and under high pressures—and the oil and gas reservoirs, when found, exist at even higher pressures (thousands of pounds per square inch), compounding the risks if a well gets out of control. The Deepwater Horizon and Macondo well vividly illustrated all of those very real risks. When a failure happens at such depths, regaining control is a formidable engineering challenge—and the costs of failure, we now know, can be catastrophically high. In the years before the Macondo blowout, neither industry nor government adequately addressed these risks. Investments in safety, containment, and response equipment and practices failed to keep pace with the rapid move into deepwater drilling. Absent major crises, and given the remarkable financial returns available from deepwater reserves, the business culture succumbed to a false sense of security.^x

It is deeply concerning that losses of well control and other incidents continue to occur on the Outer Continental Shelf without showing significant decline in the wake of Deepwater Horizon. Regarding loss of well control incidents, BSEE lists eight for 2008, a dip to three in 2011, and back up to eight in 2013 and seven in 2014.^{xi} For OCS incidents or spills, BSEE reports 871 for 2008 and 770 for 2014.^{xii}

Almost six years have passed since Deepwater Horizon, and four or five years have passed since a series of investigations, analyses, and reports were completed. Therefore, BSEE's activities to strengthen safety requirements for offshore drilling through the Well Control Rule are welcome and should be completed as soon as possible.

BLOWOUT PREVENTERS

We are concerned that the proposed rule would not require companies to deploy dual blind shear rams on all blowout preventers, even though these are a crucial last resort safety measure.^{xiii} Requiring the installation of dual blind shear rams would add redundancy to the system so that if one blind shear ram failed to sever the pipe (which can happen depending on the location and angle at the point of contact), the second blind shear ram might be able to do so.

Blowout preventers are used to "prevent the uncontrolled release of hydrocarbons in an emergency situation by mechanically closing valves or rams that block the flow of fluid from the well."^{xiv} A critical part of the blowout preventer is the blind shear ram, which "is designed to cut drill pipe in the well and shut in the well in an emergency well situation."^{xv} The blind shear ram's ability to seal a well makes it a critical component of a blowout preventer. Although other shear rams can cut pipe or casing, only the blind shear ram can seal the well completely.

The proposed Well Control Rule would require the following for subsea blowout preventer systems: “At least one shear ram must be capable of sealing the wellbore after shearing under MASP [Maximum Anticipated Surface Pressure] conditions as defined for the operation. Any non-sealing shear ram must be installed below the sealing shear ram.”^{xvi}

However, a single blind shear ram may not sufficiently seal the drill pipe. A partially or incorrectly sealed pipe can leak catastrophic amounts of oil and natural gas, as demonstrated by the *Deepwater Horizon*.^{xvii} A report commissioned by the Department of the Interior to review the *Deepwater Horizon* spill found that the one set of blind shear rams on BP’s Macondo well failed to complete a seal in April 2010 because they were jammed by a portion of drill pipe knocked out of alignment in the explosion.^{xviii} And West Engineering Services, an industry safety specialist, “found that only three of seven blowout preventers successfully sheared pipe in realistic emergency conditions.”^{xix}

The proposed Well Control Rule would require that shear rams be designed to include technology to center the drill pipe during shearing operations. While this provision will improve safety, a second set of blind shear rams is still necessary to ensure that the well can be sealed. Redundancy ensures that if one set of blind shear rams malfunctions for any reason, the other can still do its job. The Chemical Safety Board’s investigation of the *Deepwater Horizon* accident found two instances of miswiring and two backup battery failures affecting the electronic and hydraulic controls for the BOP’s blind shear ram.^{xx}

Given the importance of dual blind shear rams to offshore drilling safety, all current and future blowout preventers should be equipped with two of these devices. Because these rams serve as the last lines of defense against a blowout and also address one of the main malfunctions that led to the BOP’s inability to prevent the 2010 *Deepwater Horizon* oil spill, BSEE should place the utmost importance on companies’ ability to seal a well and prevent a blowout.

COMPLIANCE PERIODS

Oceana is also concerned that the compliance periods proposed by BSEE will cause unnecessary and potentially harmful delays. The timeline for compliance laid out in the rule is entirely too long. The rule itself comes more than five years after the *Deepwater Horizon* disaster. BSEE compounds this delay by introducing a potential three- to seven-year compliance period for some of the most crucial aspects of the proposed rule, including the installation of two shear rams.^{xxi} BSEE is also considering the inclusion of a ten-year compliance period for companies to install important technology that is capable of severing components of the drill string.^{xxii} In all, it could be more than sixteen years after the *Deepwater Horizon* catastrophe before BSEE finalizes and the industry implements these critical safety regulations. This timeline is not acceptable.

BSEE solicited comments on the proposed compliance periods^{xxiii} but offered no rational reason for the chosen compliance period lengths. BSEE, for example, proposes that “operators would be required to install shear rams that center drill pipe during shearing operations within 7 years from the publication of the final rule.”^{xxiv} However, earlier in the proposed rule, BSEE discloses, “[I]t is aware of at least one [blowout preventer] equipment manufacturer that currently has pipe centering technology available.”^{xxv} Since industry has already developed this technology, the seven-year compliance period is a needless and irrational delay. BSEE must justify the compliance periods outlined in the rule.

These unjustified compliance periods are especially worrying in light of the pervasive safety and environmental incidents caused by the offshore drilling industry. In the four years following the

Deepwater Horizon spill, BSEE reports that offshore drilling caused a total of 1,063 injuries, 477 fires and explosions, 22 losses of well control, 11 spills of over 2,100 gallons of oil, and 11 fatalities.^{xxxv} Given this perilous operational backdrop, BSEE and the Department of the Interior should quickly move forward the finalization and implementation of this rule.

Instead of including compliance periods of three to seven years from the publication of the final rule, BSEE should take aggressive action to implement stronger rules as soon as possible. Oceana's position is that new offshore wells should not be drilled when safety cannot be assured, but since offshore drilling continues to take place, compliance with these rules should not be delayed.

URGENCY OF WELL CONTROL AND BOP REQUIREMENTS

The Well Control Rule and BOP requirements are urgently needed—the more so because there are systemic problems in the regulation of offshore drilling that the agency cannot address in these proposed rules. These problems—including the inadequacy of fines and penalties, severely limited inspection and monitoring capabilities, and the potential for operator error—lead to a greater risk of accidents in the offshore oil industry and should be addressed by Congress as soon as possible. As long as these problems remain, the risk of loss of well control remains unacceptably high, and therefore these well control and BOP requirements are all the more urgent.

Inadequate Fines Incentivize Rule-breaking and Risk-taking

The monetary imbalance between current civil penalties and operating costs is too small to deter risk-taking. In fact, the exceedingly low penalties create a perverse incentive for drillers to violate rules and cut corners, with an emphasis on timely rather than safe operations. While operating costs for offshore rigs can be roughly \$1,000,000 per day, fines for violations are capped at \$40,000 per violation per day^{xxxvi}, and most violations do not even incur fines. Given this financial environment, it is easy to see why violations are so frequent.

For example, British Petroleum was paying over \$500,000 per day to use the *Deepwater Horizon* rig, and total estimated daily operating costs were approximately \$1 million.^{xxxvii} When these figures are compared to a daily maximum fine of \$40,000, it is clear that rule-breaking pays. After reviewing several corner-cutting measures taken on board the *Deepwater Horizon* rig, the Joint Investigation Team—consisting of the Bureau of Ocean Energy Management (BOEM) and the Coast Guard—concluded that “the Macondo team made a series of operational decisions that reduced costs and increased risk,”^{xxxix} demonstrating a willingness to sacrifice safety for quicker project completion.

This situation is exacerbated by the frequent usage of Incidences of Noncompliance (INCs), which can be issued in response to over 800 types of infractions but do not have fines associated with them. Although civil penalties can be assessed for INCs, they must be violations which threaten or damage human life or the environment, or that are not corrected within a specified period of time.^{xxx}

Let's look at an example from around the time of *Deepwater Horizon*. In 2009, out of 2,298 INCs issued by the agency, only 87 were referred to the civil penalty process.^{xxxi} Penalties assessed by the agency as a result of those 87 referred INCs as of June 30, 2011 amounted to just \$2.6 million^{xxxii}—less than what it cost British Petroleum to operate the *Deepwater Horizon* for three days. The fact that civil penalties assessed for a year's worth of INCs for the entire offshore oil and gas industry amounted to less than

three days of operating costs for the *Deepwater Horizon* underscores the extreme financial incentive to ignore regulatory compliance and cut corners.

This discrepancy continues to be a major driver of risk for loss of well control. We understand that BSEE cannot address this problem through rulemaking, and we encourage Congress set penalty levels that will discourage risk-taking.

Insufficient Oversight and Inspection Levels

Ensuring the efficacy of existing and new safety regulations, including the Well Control Rule, requires much more oversight than currently exists.

Inspections of offshore facilities in the Gulf of Mexico by the BOEM's parent agencies decreased over the decade preceding the *Deepwater Horizon* accident, in parallel with a shift in drilling to increasingly deeper waters^{xxxiii}, a frontier area with increased risk.^{xxxiv} This decrease was driven in part by a stagnant budget between 2000 and 2009 that failed to keep pace with oil production in the Gulf.^{xxxv} Consequently, in 2010 the agency employed just 55 inspectors in the Gulf of Mexico to inspect about 3,000 facilities, a ratio of roughly 1 inspector for every 54 facilities.^{xxxvi} This inspection rate was clearly woefully insufficient.

The agency has made some progress over the past five years. According to BSEE's FY16 Budget Justification, the agency's inspection workforce has nearly doubled since 2010, to a total of 110 inspectors in September 2014. In hiring and retaining inspectors, the agency faces considerable challenges because jobs in the oil and gas industry pay considerably higher than federal government jobs.^{xxxvii} These 110 inspectors are still spread much too thinly to adequately monitor US offshore oil drilling operations.

With Congress exerting downward pressure on the federal budget, and neither Senate nor House recommending increases in BSEE's Fiscal Year 2016 budget for offshore safety and environmental enforcement,^{xxxviii} the agency will be unable to strengthen its inspection and oversight capabilities sufficiently. Consequently, inspection rates remain anemic, undermining regulatory compliance by reducing the odds that violations will be observed. Anemic inspection rates also limit real-time oversight of operations by inspectors, a crucial need to avert disasters since problems are difficult to foresee even a few days before they occur, as illustrated on the *Deepwater Horizon*.

Insufficient inspection rates have a number of consequences for offshore safety. Compliance with regulations suffers, as the probability of regulatory violations being uncovered and penalized is tied to inspection rates. Low inspection rates also reduce the odds that an inspector will be on hand to supervise critical decisions and operations, such as those on April 19th and 20th, 2010, that led to the Macondo blowout. Although Oceana recognizes that the proposed rule would require real-time monitoring for deepwater and HTHP drilling activities, regulators are still far from implementing a robust inspection program.

Remaining Potential for Operator Error

If effective barriers to subsurface pressure and blowout preventer technology are correctly installed, these could in fact protect against blowouts. However, these requirements can easily be undermined by operator error. With limited funds for inspection and oversight, and perverse economic incentives, it is

virtually certain that there will be errors in the design, installation, and operation of these complex technologies.

Improved training requirements mandated by BSEE will reduce operator error, but ensuring that errors are avoided ultimately comes down to inspection and oversight which, as previously discussed, are still woefully lacking.

CONCLUSION

In conclusion, Oceana commends BSEE for the many safety improvements proposed in the draft Well Control Rule. We urge the agency promulgate this rule as soon as possible, and to reduce the compliance periods. Further we urge BSEE to continue to work to improve well control and BOP reliability by requiring redundant blind shear rams and other safety measures.

Even with the implementation of this rule and Oceana's recommendations, offshore drilling will continue to pose a grave threat to humans and the environment. As the *Deepwater Horizon* and the many spills before and after it have demonstrated, offshore drilling is dangerous and harmful to ocean ecosystems, to the human communities that depend upon them, and extremely hazardous to workers in the industry.

For these reasons, Oceana strongly recommends to the Congress and the Administration that offshore drilling should not be expanded into new areas in the Atlantic and Arctic Oceans. While improved safety measures are important, the only way to truly prevent the harm caused by offshore oil spills and accidents is to decrease our dependence on fossil fuels and transition to clean, sustainable renewable energy sources such as offshore wind power.

This concludes my testimony. I look forward to your questions and further discussion.

ⁱ Bureau of Safety and Environmental Enforcement and the Department of the Interior, "Proposed Well Control Fact Sheet."

ⁱⁱ Bureau of Safety and Environmental Enforcement, "Interior Department Releases Proposed Well Control Regulations to Ensure Safe and Responsible Offshore Oil and Gas Development", April 13, 2015.

ⁱⁱⁱ Summary of Information concerning the Ecological and Economic Impacts of the BP Deepwater Horizon Oil Spill Disaster, NRDC issue paper, April 2015. <http://www.nrdc.org/energy/gulfspill/files/gulfspill-impacts-summary-IP.pdf>

^{iv} Oil Spills and Tourism: They Don't Mix, Oceana fact sheet, 2015.

http://usa.oceana.org/sites/default/files/tourism_impacts_fact_sheet_9-8-15.pdf

^v Offshore Energy by the Numbers: An Economic Analysis of Offshore Drilling and Wind Energy in the Atlantic, Andrew Menaquale, Oceana, January 2015.

^{vi} Energy Information Administration, "U.S. Gulf of Mexico share of global active offshore rigs declines since 2000", September 22, 2015. <https://www.eia.gov/todayinenergy/detail.cfm?id=23032>

^{vii} UCLA website on California's new rigs-to-reefs law, <http://www.environment.ucla.edu/reportcard/article9389.html>, also Google map of California offshore oil platforms.

^{viii} Bureau of Safety and Environmental Enforcement, "Interior Department Releases Proposed Well Control Regulations to Ensure Safe and Responsible Offshore Oil and Gas Development", April 13, 2015.

^{ix} Senator Bob Graham remarks, Co-chair, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, press kit for final report, January 11, 2011. "Deep Water: The Gulf Oil Disaster and the Future of Offshore Drilling, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, p. ix. <http://www.gpo.gov/fdsys/pkg/GPO-OILCOMMISSION/pdf/GPO-OILCOMMISSION.pdf>

^x Bureau of Safety and Environmental Enforcement, OCS Loss of Well Control Incidents (LWC): CY 2008-2015 YTD, *available at* <http://www.bsee.gov/Inspection-and-Enforcement/Accidents-and-Incidents/Loss-of-Well-Control/>.

^{xi} Bureau of Safety and Environmental Enforcement, "Incident Statistics and Summaries, *available at* <http://www.bsee.gov/Inspection-and-Enforcement/Accidents-and-Incidents/Listing-and-Status-of-Accident-Investigations/>.

- ^{xiii} Draft rule, pp. 21577-8, table describing the BOP requirements. The requirement is for "at least one shear ram" that is capable of sealing the well bore, i.e., one blind shear ram.
- ^{xiv} 80 Fed. Reg. at 21,506.
- ^{xv} 80 Fed. Reg. at 21,506.
- ^{xvi} 80 Fed. Reg. at 21,506.
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- ^{xxii} 80 Fed. Reg. at 21,529.
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- ^{xxv} 80 Fed. Reg. at 21,510.
- ^{xxvi} Bureau of Safety and Environmental Enforcement, "Incident Statistics and Summaries, available at <http://www.bsee.gov/Inspection-and-Enforcement/Accidents-and-Incidents/Listing-and-Status-of-Accident-Investigations/>.
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- ^{xxviii} Joint Investigation Team. "Volume II: Report regarding the causes of the April 20, 2010 Macondo well blowout." *Report of Investigation*. 14 Sept. 2011. Page 18.
- ^{xxix} Joint Investigation Team. "Volume II: Report regarding the causes of the April 20, 2010 Macondo well blowout." *Report of Investigation*. 14 Sept. 2011. Page 178.
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- ^{xxxi} Lewis, Wilma A., Mary L. Kendall, and Rhea S. Suh. *U.S. Department of the Interior Outer Continental Shelf Safety Oversight Board: Report to the Secretary of the Interior Ken Salazar*. 1 Sept. 2010. Page 18.
- ^{xxxii} Penalty data was compiled from BOEMRE's annual reports from 2009, 2010, and the first half of 2011. There were 28 civil penalties assessed in 2009, 2010, and the first half of 2011 for violations incurred in 2009. It is impossible to determine from the annual reports whether the 28 civil penalties covered all or some of the 87 referred INCs. We assume, though, that by June 30, 2011, civil penalties had been issued for most of the INCs for which civil penalties will be assessed. Annual civil penalty reports are available at: "OCS civil/criminal penalties." *BOEMRE*. <http://www.boemre.gov/civilpenalties/>.
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- ^{xxxvi} Lewis, Wilma A., Mary L. Kendall, and Rhea S. Suh. *U.S. Department of the Interior Outer Continental Shelf Safety Oversight Board: Report to the Secretary of the Interior Ken Salazar*. 1 Sept. 2010. Page 13.
- ^{xxxvii} Budget Justifications and Performance Information, Fiscal Year 2016, Bureau of Safety and Environmental Enforcement, p. 62, p.33.
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The CHAIRMAN. Thank you, Ms. Savitz.

Thank you to each of you for your comments this morning and for joining us at this important hearing.

Let me start with you, Director Salerno. You have indicated that with the number of comments that you have received on the well control rule, as well as the Arctic rule, you are continuing to review these and to take them into account. I would certainly hope that we have your commitment this morning and going forward that as the agency is reviewing these rules, whether it is the well control rule or the Arctic rule, that you will take into careful consideration the expert comments that are offered up by the—truly, I think, some of the finest offshore operators that we have, many American companies, that you are taking those into account.

Mr. SALERNO. Yes, Senator, we are taking those into account, reviewing them very, very carefully.

The CHAIRMAN. Let me ask about what you may be considering among the revisions. There was discussion not necessarily in the oral testimony here but in the written testimony about the BSEE-approved verification organizations, the BAVOs as you call them. This is something, I know, that has been pointed out as a concern. It is also my understanding that the industry experts think that the proposed casing and cementing requirements may actually increase risk. Then there is a proposal that you take the blowout preventers off-line every 14 days.

While it does help, I guess, to actually take them out and physically look at them, but the increased risk when you take them out and put them back in again, what does that do to it? You know, if you were to do that with your car's brakes every 14 days, that does not necessarily ensure that you are going to have greater safety protection. It might actually increase your risk. So can you tell the committee what some of the revisions are to the rules that you may be considering at this time?

Mr. SALERNO. Well, we specifically asked for comment on the testing frequency on the blowout preventers. In some cases it is currently seven days, and we propose going to 14 days. So that actually represents a benefit, an economic benefit to the industry. And we have asked for a comment on whether or not that could be further extended to 21 days. We have not made any decisions on that, but we have received a lot of comment on that area. Obviously, you know, the greater the interval, you know, the less the cost to industry. So there is an interest there.

That would be offset by other measures such as increased maintenance provisions, recordkeeping provisions, and third-party oversight. So that is the offset that would still achieve a net safety benefit.

The CHAIRMAN. Let me ask specifically about the Arctic. Ms. Savitz has suggested that offshore oil exploration should not be expanded to the Arctic. Do you think that responsible offshore production in Alaska is not only beneficial to my state, to energy security, to really the economic well-being of the country, but also that it can be done compatibly with the environment?

Mr. SALERNO. As far as operating safely and in an environmentally sound manner, we do believe that is possible. That is why

we issued permits this past season to Shell in order for them to operate.

But the Arctic is different. It is a much more difficult place to operate. Unlike the Gulf of Mexico, there is not the infrastructure, as I know you are well aware. You know, should something happen and you need specialized capabilities, you really have to have it in the theater. In the Gulf it is readily available within easy reach, not so in the Arctic. So that does place an increased burden on the operator to provide that equipment in case of emergency.

The CHAIRMAN. I think Shell fully understood that, and that was why they had the number of vessels that they had, recognizing that they did not have the resources that you have in the Gulf.

But you would agree, I am assuming, that as we are seeing the departure of Shell up north, as we are seeing Statoil with the decision that they made also to return their leases, it has been suggested by the Administration or certainly the Secretary that it was due to lack of interest.

As you think about the financial investment and commitment that Shell made, over \$7 billion over a period of seven years, to get to the point where they were able to drill exactly one exploration well, it makes it pretty daunting. As they made their decision to cease further exploration activity, they said the decision reflects both the Berger well result, which was disappointing—we recognize that—the high cost associated with the project. Again, there is a difference between the Arctic and the Gulf, and we recognize that means higher costs. I do not think that Shell anticipated it would mean \$7 billion to get to one well, but also the challenging and unpredictable Federal regulatory environment in offshore Alaska.

That is, of course, what we are talking about today and how we can ensure that there is a more predictable Federal regulatory environment and one that acknowledges the fact that, yes, the Arctic is different, but it is also different in some ways that make it less complicated, the fact that you are not drilling in deep water, the fact that it is very shallow. So we will explore these in the next round.

I will now turn to Senator Cantwell.

Senator CANTWELL. Thank you, Madam Chair. As somebody who spent many hours when Congress was dealing with this issue in the aftermath of the actual explosion, I am reminded of the actual report that was done by the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. There was a lot of discussion then about what should be done.

In fact that Oil Spill Commission put out a letter just last year saying President Obama's Oil Spill Commission made fundamental commonsense recommendations, including Congressional action on improving safety for rigs, eliminating conflicts of interest in regulatory agencies, expanding liability limits of companies to make sure that they have adequate resources for emergencies. These have been ignored by Congress, by the way.

So the notion that we are here today focusing on the one thing that did get implemented, which in my opinion could have gone further. Having sat through those hearings on blowout preventers, I would have implemented immediate third-party validation. Given what the blowout preventer provides in this particular instance, I

would have gone further. So here we are now and some people are trying to delay a rule that is so vital to helping us not have the same accident happen again.

Mr. Salerno, I wanted to ask you about the process by which preventers are going to be verified—you just talked about the five-year process—but how we are going to get third-party verification so that we know that blow out preventers are working correctly to begin with and how are we going to have oversight of that in the future?

Mr. SALERNO. Yes, Senator. They are features of the proposal. You know, there would be third-party certification to make sure that the blowout preventers actually function as intended, that the testing provision, periodic recertification of the BOP functions and making sure that they continue to operate as intended.

The third-party provisions, they were stepped up after 2010, but this takes it to a little more rigorous level. The BSEE-approved verification organizations are essentially the next step in building out what already exists within the industry as a cadre of third-party verifiers. But we want to put more specificity as to what that means, greater clarity as to the standards that will be used for BOP testing.

Senator CANTWELL. So that will be developed over time? Is that what you are saying?

Mr. SALERNO. That is correct. It would be developed over time. We put it in the rule. The use of the BSEE-approved verifiers would take place one year after we publish a list of who those verifiers are. We anticipate that many of the companies that now do verification would apply to be the BAVO in that category. There are a number of companies out there who would do that.

Senator CANTWELL. Ms. Savitz, is your concern that the rule is not stringent enough or the conditions of the Arctic were not taken into consideration?

Ms. SAVITZ. Well, our concerns with the rule are general about how the rule would be applied anywhere, including the Arctic. In specifically looking at the well control rule, our concern has to do with the fact that we do not believe this rule will necessarily prevent an oil spill, but we do think that it improves the status quo. It makes drilling a little safer. It does not mean drilling is safe.

For instance, in the Deepwater Horizon, for example, we had blind shear rams that did not succeed in severing the drill pipe creating a barrier to flow. There is no redundancy in the requirement for blind shear rams in this rule. There is no requirement that the blind shear rams are able to sever tool joints. So there are still some things that need to be looked at and strengthened.

But the idea that we are sitting here now almost six years after that, those hearings that you mentioned, still talking about putting in place rules to deal with the last line of defense, the failsafe in offshore drilling, is incredibly disturbing. I know that as we all sat there during the Deepwater Horizon and watched the oil gushing from that well day after day after day thinking if only there was something we could do, and there was nothing we could do at that time. The only thing we could do was stop drilling in deep water and stop drilling offshore, but short of that, let us put some safety

measures in place. And, in fact, we are finally getting around to doing that. It is not a moment too soon.

Senator CANTWELL. Thank you. Thank you, Madam Chair.

The CHAIRMAN. Senator Cassidy.

Senator CASSIDY. Thank you, Madam Chair.

Well, first, I thank you tragically for the pictures of those who died. I knew the families of one of them. So I agree that it is in their honor that we come here to try and prevent this from happening again.

I will also point out that one of the widows of one of those who died opposed the moratorium, saying that several people in her house and on her street depended upon the income from working on those rigs in order to support their family.

So clearly there is a balance here. How do we achieve safety but not kill an industry with a thousand cuts, an industry which is so important to the livelihood of so many?

So that said, Mr. Salerno, I have several questions frankly based off of Mr. Milito's testimony because, again, my technical expertise is not in this area, but common sense sometimes applies. He points out that your requirement of 20 new receptacles, which would involve shuttle valves, hoses, tubings, etcetera, for the ROVs to attach to is in and of itself a recipe for potential leaks and malfunctions. That makes sense. I am a physician. I know that when you have equipment, the more Rube Goldberg-ish it is, the more likely it fails. Now, the 20 new receptacles, do you disagree that that would create more possibility for leaks, etcetera?

Mr. SALERNO. We do not believe it would increase the risk, but, Senator, we have received again a volume, great volume of technical feedback from the industry, which we are now considering.

Senator CASSIDY. Intuitively, though, the more openings you have to a system, the more points of vulnerability you have. I mean, I think that is a general, you know—a sieve is more likely to leak than something which has only one opening. Twenty more receptacles seems to make it more like a sieve than it does something with only one opening. Is that not true?

Mr. SALERNO. It is also true, sir, that if you needed an ROV to actuate functions on the BOP and you did not have the means to do that, you incorporate risk in that fashion as well.

Senator CASSIDY. Now, it is implied in the testimony that there are 23 existing panels, I presume, for 23 places for ROVs to currently attach. But this would be in addition to those in which the ROV can currently attach?

Mr. SALERNO. I would have to check—

Senator CASSIDY. Mr. Milito, is that in addition to?

Mr. MILITO. Yes, the proposed rule would require 20 additional receptacles.

Senator CASSIDY. Additional. So there are places now for the ROVs to attach, but there are 23 more, again, 23 more potential points of failure. Now, again, there are going to be smarter people than me that figure that out.

Second, the disassembling of the BOP every five years, that in itself seems to be a point of hazard. In medicine it is an axiom if you do procedures, ultimately, you will have an accident. This is a procedure, and it introduces the possibility for human error every

five years in the disassembling and the reassembling. Again, that is intuitive and that is based upon real-life experience, but tell me why you apparently disagree with that.

Mr. SALERNO. Well, a five-year interval was actually based on an API standard, API Standard 53. So that is where the five years comes from.

Senator CASSIDY. Now, Mr. Milito, you raise that as an objection in your testimony. How would you respond to that?

Mr. MILITO. Yes, our concern is that over the course of five years the maintenance occurs through different components of the blow-out preventer, so by pulling the whole BOP out of service for that length of time is not justified given the way that the industry operationally maintains, inspects—

Senator CASSIDY. So API's feeling is that you could do it piecemeal and accomplish the same goals without the need to completely deconstruct?

Mr. MILITO. Absolutely.

Senator CASSIDY. Okay, okay. When you piecemeal, do you eventually piece the whole meal?

Mr. MILITO. Absolutely. The five-year requirement means that you have got to get through the whole BOP over that five-year period.

Senator CASSIDY. Why is that not adequate, Mr. Salerno?

Mr. SALERNO. Well, Senator, we have received a lot of comment on that, and those are comments we are considering.

Senator CASSIDY. Okay. Then let me also ask, and I think this is really key. You mentioned in that Chevron explosion—no, the Walter Oil & Gas, that there was a kick that was not recognized. In the Macondo there was a kick which was not recognized. That is all human error, and it requires situational awareness. Milito's testimony suggests that the rule shifts responsibility for operational decisions away from the rig to those who are not onsite, they are remote.

But by doing this, you transfer authority from those who do not have a situational awareness to those who might be far away with inevitably some lag time in communication and perhaps some, you know, "oh my gosh, I have got to go to the bathroom, I will be right back" sort of incidents up there in Houston.

So, that said, again, intuitively, it seems like you would want authority to rest with those with situational awareness, those who are onsite, those who could administer the CPR when the person goes down, not wait a second, can you tell me if I should do mouth-to-mouth? I will get on it as soon as you let me know. Thoughts?

Mr. SALERNO. Yes. The rule does not shift command-and-control authority from the rig to shore. It addresses capability so that there will be a second set of eyes so that you can have, you know, extra experts on shore to provide diagnostic expertise to assist in assessing an anomaly.

The decision as to where command and control resides is with the company. So we talk about capability, not where the command and control resides. So people have interpreted it that way. It is an incorrect interpretation.

Senator CASSIDY. My time is over. I yield back. Thank you.

The CHAIRMAN. Senator Warren.

Senator WARREN. Thank you, Madam Chair.

So when BP's Deepwater Horizon oil rig exploded, it killed 11 workers and it set off an oil gusher that spewed millions of barrels of crude into the Gulf of Mexico. It covered an area ultimately that was the size of Florida. Nearly a million seabirds died, sea turtles washed up dead, choked to death by oil in their throats, workers and small businesses lost literally billions of dollars. The BP oil spill was a massive catastrophe by any measure, and we are here today to make absolutely sure this catastrophe does not occur again. So finally, 5-1/2 years after the explosion, the Administration has proposed a drilling safety rule to address some of what went wrong with Deepwater Horizon.

Mr. Milito, you are here representing the oil industry, and in your written testimony, which I looked at last night, you argue that offshore drilling—and I want to quote this correctly—is “safer today than it ever has been” and that “new safety rules for industry are too prescriptive and would just prevent you from conducting more drilling.”

Now, this is not the first time you have made that kind of claim. Exactly ten days before the Deepwater Horizon disaster, you criticized opponents of offshore drilling and said that people should not be concerned about offshore drilling because offshore drilling is “very low risk” and new technologies “close and shut off any type of opportunity for any kinds of liquids or fluids to get into the environment.”

So here is my question. Do you still think that the opponents of offshore oil drilling were wrong to be concerned about the risks involved in offshore drilling ten days before your industry caused an historic disaster?

Mr. MILITO. I think we should always be concerned about the potential for any kind of—

Senator WARREN. So you think that we are right to be concerned?

Mr. MILITO. Oh, yes, we should always be concerned about these types of incidents from occurring, and the original quote in there was actually from the Commissioners of the Presidential Deepwater Oil Spill Commission who said it is safer now than it was five years ago. So that was coming from—

Senator WARREN. So when you said “very low risk” and “close and shut off any type of opportunity for any kinds of liquids or fluids to get into the environment,” when you said that ten days before this massive explosion, you were wrong, I take it?

Mr. MILITO. Well, that is—my belief still is today that it is a low-risk activity and that we can continue to do this with a performance-based system that—

Senator WARREN. So you feel the same as you did ten days before that explosion?

Mr. MILITO. I feel that we have a regulatory framework that has changed dramatically—

Senator WARREN. I am not asking about the changes. I am asking about you said ten days before the explosion that new technologies “close and shut off any type of opportunity for—

Mr. MILITO. That—

Senator WARREN.—any kind of liquids or fluids to get into the environment.”

Mr. MILITO. That is the intent of technologies, and that is——

Senator WARREN. The intent, but I take it that was not the fact.

Mr. MILITO. That is not how it is done.

Senator WARREN. No, that is not in fact. You know, in fact, your whole industry has dismissed safety concerns. Just weeks before the BP oil spill Jack Gerard, the head of the American Petroleum Institute, who I think is your boss said, and I will quote again, “the oil and natural gas industry has a proven track record”—words that I think you have used here this morning—“of safe oil and natural gas development.” Again, this was just weeks before the Deep-water explosion.

The oil industry comes in here repeatedly and explains that it is doing a great job on safety, and it says, like before, they do not need more oversight. But considering this is exactly what the oil industry was saying right up until the minute the BP rig exploded, I think the American people are right to be a little skeptical of oil industry claims.

So, Ms. Savitz, you are a marine biologist who has been a leader on ocean conservation issues for decades now. Now that the Government is bowing to industry pressure and proposing to expand oil drilling into the Atlantic Ocean for the first time in decades, are you confident that current industry practices will protect us from another BP disaster?

Ms. SAVITZ. Thanks, Senator Warren. Of course not. Of course we are not confident of that. And I think the takeaway point from the conversation you are having is the industry simply, seems like, did not anticipate the scenario that played out during the Deep-water Horizon. They did not anticipate the shift in the way the drill bore landed in the annulus, and their equipment was not capable of dealing with it.

Will the same thing happen again in the next one? Maybe, and maybe they will be prepared this time because maybe they learned something, or maybe something completely different will happen. And there is no way to know that and there is no way to know that we will be able to stop it if it does happen.

If there is such a spill, we are talking about major losses to coastal economies. We have seen a lot of communities now rising up against that. Ninety-one coastal communities have passed formal resolutions against offshore drilling.

Senator WARREN. We cannot afford the environmental or the economic cost of another BP spill. So it seems to me that before new oil rigs are set up in the Atlantic, we need to take a very hard look at what additional drilling would actually mean. The discussion is too important to simply take the oil and gas companies at their word when they tell us, like they did 5-1/2 years ago, that they have got it all under control.

Thank you, Madam Chair.

The CHAIRMAN. Senator Daines.

Senator DAINES. Thank you, Madam Chair.

I can say I certainly appreciate BSEE’s desire to develop offshore energy safely. I say that as an avid outdoorsman, someone who en-

joys the streams of Montana, the mountain peaks, and hunting and backpacking and so forth, and protecting our environment.

But this proposed rule is concerning, and I believe it represents yet another step in the Obama Administration's efforts to reduce American energy production. As we are looking at it, I am trained in chemical engineering, and looking at the tradeoffs in risk management certainly, and looking at how do we protect national security, how do we protect our environment, how do we protect our economy, because they have to weigh all these factors to come up with good, sound rules and policy.

In BSEE's own words, it said "it is one of the most substantial rulemakings in the history of BSEE." The proposed rule indeed is extensive. It is overreaching its requirements and they are more stringent than current global standards, yet the proposed rule and BSEE's rulemaking process have demonstrated a disregard for the states that will be affected where offshore oil and gas production means good-paying jobs, it means significant tax revenues, it is the livelihood of tens of thousands of American families, and it is a trend that we are seeing far too often, in my opinion, with this Administration's rulemaking, including my home State of Montana with the current Clean Power Plan.

The Clean Power Plan, which I think would be better described as the Unaffordable Energy Plan, the University of Montana just released a study two weeks ago. It will cost our state 7,000 jobs and \$145 million in tax revenues. So those are revenues that go directly to pay for our schools, for our teachers, for our infrastructure. In fact, the University of Montana study concluded that it is the most significant economic event to occur in Montana in over 30 years. This is what is at stake in coming out of Washington, DC and the EPA.

So my question for Mr. Salerno, BSEE expects the proposed well control rule to cost over \$883 million over the next ten years. While their analysis does not address the number of jobs lost, others project a loss of over 50,000 jobs by 2030, as well as monetary costs much higher than what is currently cited. I wonder if you would please address these estimates, as well as my concern that this rule would set the stage for additional regulations on drilling, including offshore development.

Mr. SALERNO. Well, Senator, there is no intent to shut down drilling in this rule. The intent is to make it safer and to be, you know, environmentally responsible as the companies pursue offshore energy resources.

We have asked for additional cost information from the industries, one of the specific requests in the proposal. We have received some of it. But I have also observed comments in the press, which, you know, basically reflect, you know, your concerns. From my perspective, in many cases it is a misinterpretation of certain provisions of the rule where there are assumptions that we will make certain types of drilling impossible—

Senator DAINES. So are you challenging—is the analysis wrong? The 50,000 jobs lost by 2030, that is not accurate? It is a bad analysis?

Mr. SALERNO. As—

Senator DAINES. Is it bad algebra? What is it?

Mr. SALERNO. As a result of this rule? Yes, I think it is a bad analysis.

Senator DAINES. So, Mr. Milito, can you explain the jobs in the cost analysis that is cited in your testimony as well as perhaps others?

Mr. MILITO. Yes, and I would like to repeat that our focus here is on a driving a rule that advances safety. That is the objective that we have, and we wanted to make sure that we understood where the Government's cost estimates matched up with what independent engineering consultants would come up with. And that is why we did it, and we saw the disparity between \$883 million over ten years versus the \$30 million and felt that that in and of itself is a compelling disparity that should really force us all to relook at the rule.

What Blade did is they looked at the provisions of the rule, they determined, you know, what the overall cost and investment impacts would be, the delays, and they came up with, you know, the drop in production of 500,000 barrels a day, the drop in investment, and also the associated job loss that would come from that. So it is really based upon the expertise coming out of a lot of engineers in an engineering firm, along with the economic analysis that brought out those numbers.

Senator DAINES. So have you had any challenges? I mean, it sounds like it has been a thorough, well-thought-out, reasonable set of assumptions that come to these conclusions. Is anybody challenging your numbers?

Mr. MILITO. I am not aware that they are, but once again, you know, we want to focus on making sure that the requirements of the rule are really advancing safety and not really impacting the safety elements of offshore in a negative way. And given that, you know, some of these provisions may not do that, it may increase costs, then you are really not justifying those elements of the rule.

Senator DAINES. Right. Thank you. Thank you, Senator.

The CHAIRMAN. Senator Franken.

Senator FRANKEN. Thank you, Madam Chair.

I was here five, six years ago when the Deepwater Horizon tragedy happened. This is 11 workers killed, and I guess \$20 billion of cost to BP and all the damage to businesses and etcetera, etcetera. We want to prevent this from happening again.

The issue seems to be here whether this is over-prescriptive. Can I get a sense from either Mr. Milito or anybody here on what have been the improvements since the BP disaster and whether those are going to be carried through here and how is this over-prescriptive considering the incredible environmental damage and loss of life? And, Mr. Milito, the Senator from Massachusetts did quote you as saying beforehand that this was not going to happen. So how can we be assured that it will not happen again?

Mr. MILITO. Yes, that is a great question, Senator Franken. I think if you look back to 2010, we worked closely with the Government. The Government issued the safety drilling rule in that year just six months after the Gulf oil spill. That rule in and of itself requires a blowout prevention system, casing and cementing requirements, testing, maintenance. We actually have in that rule third parties that have to come in and certify and validate that

your blowout prevention system is going to work in compatibility with the system.

We also now have requirements for safety and environmental management systems. API put out a standard well before the spill on the safety environmental management systems, and that is a key part of offshore safety because it forces companies to create a system-wide approach to safety, and it requires them to be audited to make sure that there is truly a culture of safety that is being reflected in our operations. So a lot has happened. We do not oppose the well control rule. We just want to make sure that we get it right.

Senator FRANKEN. I understand. We have seen too many loss-of-well-control events since BP. There have been no deaths, there have been no great disasters, but I am interested in Mr. Salerno's perspective on how safety has improved when it comes to drilling in the Gulf and just your sense of how the well control rule does and does not implement recent technological advances or how it does more.

Mr. SALERNO. Yes, and thank you, Senator.

Well, there have been improvements, as Mr. Milito mentioned, of the drilling safety rule, but they were sort of initial first steps. There are a number of provisions left, you know, unresolved that came out of these many studies after Deepwater Horizon.

For example, technology to center the drill pipe in a BOP so that the shearing rams will actually work effectively, that has not yet been fully addressed. That will be addressed in this rule. There are some provisions in the industry standards which, although generally helpful, fall short of things we believe really need to be included such as double shear ram on surface BOPs. That was discussed in the industry standards, but there is an opt-out provision. So if a company feels that it is not appropriate for their operations, they can opt out of it. We feel that needs to be a little bit more strenuous. So there are a couple of examples where we feel we are not quite there yet. This rule will address those.

Senator FRANKEN. Okay. I guess here is a big question. There is a movement to keep it in the ground. Some of us are going to Paris for this climate summit. The price of oil has gone down, the price of gas has gone down. Is there some sense that we should be looking at what oil we might want to keep in the ground and base that partly on safety? Ms. Savitz?

Ms. SAVITZ. Yes, Senator, thank you.

You know, we believe that expanding drilling into frontier areas like the Arctic and the Atlantic would be a good place to draw the line to start with, to say let us not industrialize our coasts that do not already have oil drilling. And in those areas, especially in the Atlantic, we have heard the Atlantic referred to as the Saudi Arabia of offshore wind.

So while we cannot stop drilling overnight, we also cannot start developing clean energy overnight. We have to start developing clean energy now, encourage that development so that we can get the benefits that it brings. Offshore wind, for instance, on the Atlantic could be powering many homes, in fact, would create 90,000 more jobs than developing offshore oil in the same area.

So it is really not jobs versus the environment. It is really jobs versus jobs. Do you want dirty energy jobs or clean energy jobs? And if you go with the clean energy jobs, besides getting more energy and more jobs, you also get less pollution, less carbon in the atmosphere, and you can avert the worst impacts of climate change.

And so the real key here to me is, you know, we can hope that the industry is doing a better job even though the statistics do not necessarily demonstrate that, but if we really want to stop offshore drilling, we have two choices: stop the drilling or put really strong regulations in place.

We cannot count on industry to do that themselves. They have developed drilling technology in deeper and deeper waters without simultaneous development of prevention technology. They have a history of cutting corners. That is what we saw with Deepwater Horizon. So we either have to regulate it or we have to draw the line, and we would draw the line.

Senator FRANKEN. Okay. Thank you, Madam Chair. I would note that you are from Alaska, and I am from Minnesota, and we do not have any oil not to drill. So it was easy for me to ask that last question. [Laughter.]

The CHAIRMAN. Senator Gardner.

Senator GARDNER. Thank you, Chair Murkowski.

And our oil is at one time—deep water is longer from Colorado, deep water. [Laughter.]

Thank you very much to the panelists for being here today.

I wanted to follow up a little bit on what Senator Daines mentioned before to Director Salerno. He mentioned that BSEE does not address jobs lost in the rule. Could you explain the process of when you will look at that consideration, an economic consideration of costs-benefits, jobs lost?

Mr. SALERNO. Well, we do not anticipate that there will be a reduction in drilling as a result of this rule, so it is not really a job-loss issue. It is an increase-in-safety issue. Now, some of the—

Senator GARDNER. Will you come out with an official finding of economic benefit versus cost and say that you believe that there is no job loss? Is that part of the requirement—

Mr. SALERNO. There is an economic analysis, a cost-benefit analysis required. It is a regulatory impact analysis. That is publicly available. It is scrutinized at OMB, which does a very thorough job—

Senator GARDNER. That is already available, you said?

Mr. SALERNO. Yes, sir, it is, and it will be revised based on additional cost information that we have received through the comments.

Senator GARDNER. Thank you. My experience in Colorado in 2000—I believe it was 2007—there was a regulatory rewrite of some oil and gas rules. One of the rules had talked about a certain type of valve that was—I think the rules prescribed that it was to remain closed during operations of oil and gas drilling activities.

The challenge with this prescription, though, was that it affected the western slope of Colorado differently than the eastern plains of Colorado, two different geologic conditions, as well as topographic conditions. One area relied upon groundwater and another area re-

lied upon surface water, and this prescription drove a lot of the conversations about whether or not we should have a one-size-fits-all rule that actually might make it less safe in operation in parts of Colorado as they tried to make this fit for everyone.

Based on the concerns that we have heard today and the testimony that we have heard today, is there a concern that this one-size-fits-all model could result in a higher level of risk, as we have heard today with various testimony?

Mr. SALERNO. No, I think those comments really ignore the fact that our regulations already, the current ones, include provisions for alternative compliance so that if a regulation does not fit a particular circumstance, a company can come in with a proposal for an alternative way to achieve the level of safety that is envisioned. That it is reinforced in this proposed rule in several places.

So even where we have put in targets—you know, safe drilling margins is probably the best example that has caught industry's attention, that was put in there with the expectation that there will be circumstances where that target may not be achievable or even the best target. But it is something that is managed through the permitting process, that dialog back and forth between my agency and the industry to come up with, you know, what is acceptable for that particular well.

Senator GARDNER. Mr. Milito, would you like to respond to that?

Mr. MILITO. Yes, and it is a great point on prescriptiveness versus performance-based regulation. And if you look at what has been occurring over the past five years, we have seen, you know, over 150 of these wells related to that particular provision drilled safely. So we think the system is actually working. It provides the ability of the industry to work with the permit approvers to come to a final decision based upon the overall risk of the operation.

Our overall concern is that when you make it into a reg, they can become extremely rigid. And if you look at some of these requirements, they actually could force bad behavior by redesigning a well, not looking at the best and optimal ideal mud weight. There are different issues that could arise, and if you are already in a prescriptive environment, which the regulations currently are, and you are adding prescriptive elements to it, it becomes more difficult as a regulator to really, you know, go back and adapt those regulations.

We develop our standards, which we are pleased to see the agency adopting, but we are able to go back and revise those rather quickly and make sure that we are keeping up to date with the technologies.

The last thing I would like to note is that, overall, we are very supportive of a majority of the provisions in this rule. There are certain provisions in it that we have concerns about from a safety standpoint.

Senator GARDNER. Well, and I think that some of your colleagues, Director Salerno, at the Department of the Interior I have recently had conversations with regarding the EPA's failure to fully understand the complexity of the Gold King Mine, that the release of three million gallons of toxic material into the river by the EPA—the Bureau of Reclamation, the Department of the Interior actually did an analysis on the cause of that and what happened.

It has been clear through those conversations the Bureau of Reclamation believes that you cannot have a—because we were talking about how do you prevent that kind of release of toxic material from happening again in the future? Do we need industry—you know, a standard across the government that does not exist right now?

It became very clear from our conversation with the Bureau of Reclamation that they believe a one-size-fits-all approach to Federal compliance would actually be counterproductive, that there is no way to see how a mine differs from another mine. To put a prescriptive overlay upon them all would not be in the best interest of safety.

So with the concerns that Mr. Milito just expressed, is there not a point to some of the prescriptions that they agree go too far and actually have an adverse or inverse affect on safety?

Mr. SALERNO. Again, Senator, I would point out that there is a longstanding provision in our regulations for alternative compliance to address those very concerns, and it is a well-exercised one. The industry uses it regularly, but we have that dialog with our subject matter experts to make sure that the regulations are applied in an appropriate way.

Senator GARDNER. Thank you. I will just end by raising some of the safety issues we have heard, I think, from testimony before both the House and the Senate from Secretary Moniz, Secretary Jewell, and EPA Administrators Jackson and McCarthy that there has never been a single incident of contamination of groundwater through hydraulic fracturing. So we have made tremendous progress in safety and continue to do good work.

The CHAIRMAN. Thank you. Senator Hirono.

Senator HIRONO. Thank you, Madam Chair.

Mr. Salerno, I heard you say just now that there is an alternative compliance provision or structure so that with regard to any particular rule it is not one-size-fits-all?

Mr. SALERNO. That is correct, Senator.

Senator HIRONO. So can you give me an example of where the oil and gas industry has used this provision to modify the impact of a rule?

Mr. SALERNO. There are various technical provisions in the regulations which, you know, may or may not be appropriate in any given situation. And so there is a general provision within our regulations currently. It is reinforced in several locations in the proposal so that, anything for, you know, exploratory drilling, for example, there is a provision in there saying any provision in the subchapter, if the operator wishes to propose alternative compliance, they can do so. So that is done. It is generally managed down at our regional level, people who are closest to the scene, subject matter experts who can engage in that dialog with the industry.

Senator HIRONO. Thank you. According to your testimony, your Bureau is now reviewing over 5,000 pages of technical feedback on the draft rule. Can you elaborate on how you engaged with the oil and gas industry in developing the rule to ensure that the rules are practical and there are practical steps to reduce the risk of accidents and death?

Mr. SALERNO. The engagement was very extensive. Quite honestly, it started with all of the technical analyses from the various commissions—studies, reports, recommendations that came out of the Deepwater Horizon. That is what is here. And there was a tremendous amount of industry engagement in the production of these studies. That was followed with workshops, with meetings with industry associations, with individual companies, other stakeholders over the course of several years to really go through the details of this. And out of all of that we generated the proposal.

With the proposal being published in April, of course, there was a comment period, ultimately 90 days. That is when the 5,000 pages were presented to us. Subsequent to the closing of that comment period, we had some very narrowly tailored meetings with industry to get additional clarification on the comments, which were submitted during that timeframe. And in fact, we have one more meeting scheduled for next week along those lines just for additional clarification, not new comments, but just to clarify what they provided. So all told, again, it has been about 50 different meetings with industry—

Senator HIRONO. Did you say 5-0?

Mr. SALERNO. Five-zero over the course of several years to develop this proposal and to perfect it.

Senator HIRONO. Thank you. For you again, Mr. Salerno. If the environmental and safety regulatory standards laid out in the WCR are implemented, operators will have to factor in the cost of the compliance with the rule in addition to their operating costs. Can you speak about the economic impact operators will face when complying with the WCR and does this cost of compliance outweigh the benefits of avoiding another Deepwater Horizon disaster?

Mr. SALERNO. We did estimate about \$880 million over a ten-year period. That includes, you know, direct costs for compliance with new provisions. We assume compliance with the industry standards already. Some of the provisions in the rule such as spill containment is already required, so that is not a new cost. There are also some benefits to the rule such as the change in the inspection frequency of BOPs from 7 to 14 days, and should it go to 21 days, that would be even an additional benefit. So all of that was considered in calculating the overall cost.

Senator HIRONO. Did you also take into consideration—I realize this is difficult to predict because you do not want to make any predictions based on the actual occurrence of disasters—but when there is a disaster and there are deaths, then the company ends up paying huge amounts in settlement costs. For example, BP is facing some, what, \$20 billion.

Mr. SALERNO. Well—

Senator HIRONO. Were those factored in or considered in some way?

Mr. SALERNO. Yes, we did look at the cost—the benefit, quite honestly, of avoiding oil spills, avoiding loss of life, and there are actuarial tables that we used that are included in the cost-benefit analysis. So yes, they were considered.

And on the BP, yes, it was about \$20 billion for a response cost, but if you look at their legal liabilities and fines and penalties, it is actually closer to \$60 billion. So that is a significant cost that

I think any company would seek to avoid, and if that can be avoided, that is also a benefit to this rule.

Senator HIRONO. Thank you. Thank you, Madam Chair.

The CHAIRMAN. Senator Barrasso.

Senator BARRASSO. Thank you, Madam Chairman.

Mr. Salerno, a number of the stakeholders are concerned that the proposed well control rule may actually increase, not decrease, the risks involved in the offshore oil and gas production. The stakeholders argue that the proposed rule is excessively prescriptive. In other words, the proposed rule too often specifies how industry must achieve the rule's objectives. Stakeholders argue that the proposed rule should instead be performance-based. In other words, the proposed rule should establish objectives for the industry while allowing the industry to develop the best methods to achieve the objectives.

Stakeholders raising these concerns are not just oil and gas producers. They actually include government agencies, agencies like the U.S. Chemical Safety and Hazard Investigation Board. You know, in July of this year, that Chemical Safety Board submitted comments to the proposed rule, and in its comments, the board explained that—let me just go through this—“while minimal compliance requirements may be necessary, prescriptively requiring them can lead to safety plateaus rather than continued safety improvements that meet or exceed the standards identified by the proposed rule.” They went on to say that they were concerned that some of the prescriptive requirements and even the standards identified in the proposed rule may not always reflect current industry best practices.

So the question is, how do you respond to the concerns that both the Chemical Safety Board and the oil and gas industry have raised about the proposed rule?

Mr. SALERNO. Well, we have heard concerns about prescriptive language. Our intent, quite honestly, is to approach it as a hybrid, to provide enough specificity in the rule so it is very clear what the standard of safety envisioned is so it is clear what the target is for the industry, but also provide the provisions for alternative compliance should new technology become available. We do not want to lock in today's technology for the future. If somebody can develop something better, obviously, we are very interested in that, so provide a pathway for that but to make sure that it achieves at least that level of safety envisioned in the rule.

Senator BARRASSO. Yes, because this is highly unusual for a Federal agency and the oil and gas industry to both agree that a proposed rule issued by another Federal agency would inhibit safety advances. It does not happen every day, does it?

Mr. SALERNO. Well, we disagree with the assertion that this would—this rule would make things unsafe. I mean we are a safety organization. Our whole purpose in life is to make things safer, not less safe. So these concerns that have been raised, you know, we are taking them very seriously and we are considering how best to address those as we move forward with the finalization of the rule.

Senator BARRASSO. Mr. Milito, would you like to respond to Mr. Salerno?

Mr. MILITO. It is a great question, Senator Barrasso. I think what it comes down to is making sure we have a proper balance of regulations that are advancing safety yet at the same time encourage innovation and the advancement of technology.

What we have done in the past several years is develop industry standards which really create a strong baseline which gives you that performance-based element to move forward with safe equipment, safe operations, and the blowout prevention equipment document we put out is being incorporated and referenced as a requirement. Our concern is that they are adding on a lot of different elements that were not considered in the process of developing an industry-wide standard. The BSEE experts were at the table in the development of that.

So once you go outside of a process where things were thought out and developed according to a consensus, then you are adding prescriptive elements on that may not make sense in the eyes of the experts. So it is very important to have that balance, and we would like to see more of a performance element when it comes to things like blowout prevention equipment.

Senator BARRASSO. Mr. Salerno, yesterday, the international climate negotiations began in Paris. The President is there this morning. The goal of the conference, they say, is to reach an agreement to reduce carbon emissions worldwide. Two members of this committee believe the United States should unilaterally end oil and gas leasing on Federal lands and waters. The members have introduced legislation to do just that. It is called the "Keep It in the Ground Act." So the question is, do you believe that ending oil and gas leasing on Federal lands and waters is a reasonable and effective way to reduce carbon emissions worldwide?

Mr. SALERNO. Sir, that is way above my pay grade. My role is, where leasing is done and drilling is permitted, that it is done safely. And that is the focus of this rule. It really does not get into national energy policy.

Senator BARRASSO. But would—actually ending the oil and gas leasing on Federal lands and waters, is that a reasonable and effective way to reduce carbon emissions worldwide?

Mr. SALERNO. I will defer to my other agencies within the Department of the Interior on the leasing issues, sir.

Senator BARRASSO. Well, you are the Director of the Bureau of Safety and Environmental Enforcement, so I would just like to get your thoughts on this proposal.

Mr. SALERNO. Yes, the environmental enforcement has predominately to do with keeping oil in the pipe, you know, in drilling activity and in production activity. It is making sure it goes where it is supposed to go, not into the ocean. So that is the boundaries of my authority. So I would be stepping way out of my lane to venture an opinion on some of these other questions, sir.

Senator BARRASSO. Thank you, Madam Chairman.

The CHAIRMAN. Thank you. Senator Hoeven.

Senator HOEVEN. Thank you, Madam Chairman. I would like to thank all the witnesses for being here today.

I want to start with Mr. Salerno and really continue the questioning that both Senator Gardner and Senator Barrasso have been

asking you about as I came in here, and that is this concept of a Federal one-size-fits-all rule. Is that what we have here?

Mr. SALERNO. I do not believe so. There is alternative compliance language in our current regulations and again reinforced in the proposal. So it allows for the fact that certain situations may require different solutions.

Senator HOEVEN. So, Mr. Milito, tell me about that alternative language. Does that provide the flexibility that works for industry?

Mr. MILITO. I think the baseline regulation should be really reflective of the best regulatory language you can have to advance safety, and we should not be starting out with a baseline that has language that could potentially have unintended consequences that also increase risk.

We are also concerned about having to rely on alternative compliance decisions, which are becoming more and more difficult to come by over the past five years. And it puts the industry in the position of having a very uncertain regulatory environment if you are not relying on the underlying regs to get your permit approval. So we have a lot of concern about having a predictable, certain regulatory environment when you are relying on alternative compliance decisions.

Senator HOEVEN. Mr. Salerno, how would you address that?

Mr. SALERNO. The specificity in the rule does provide a target. If we did not provide a target, that becomes uncertain in its own right. It always becomes a matter of dialog, you know, at some point between the industry, by the company that is seeking to drill a well, and the technical experts that are reviewing the permit application. But at least that is a starting point and where the discussion begins, and everything is evaluated against that target.

Senator HOEVEN. Before the Bureau finalizes the rule, will you be incorporating the additional recommendations from industry stakeholders like Mr. Milito?

Mr. SALERNO. We are considering all of the comments from industry, from other stakeholders. Right now, we are in that deliberative process, which is where we consider how and if the language in the proposed rule would be modified.

Senator HOEVEN. Well, what I hear is your alternative compliance provisions are not adequate. Are you willing to address them?

Mr. SALERNO. Well, we believe they are adequate because they are currently being used, and they again are reinforced in the proposal. But again, we have got numerous comments from the industry, from other stakeholders as well, and we are considering all of those comments, including the use of alternative language as we move towards finalization.

Senator HOEVEN. Ms. Savitz, would you not agree that one-size-fits-all is problematic given all the different conditions that we have in terms of whether we are drilling in deep water, shallow water, different parts of the world, different places offshore? And so is not flexibility a necessary part of a good rule?

Ms. SAVITZ. My understanding, Senator, is that the role includes both some prescriptive requirements and also some that have flexibility and that BSEE is working through the comments from the industry to determine which ones it is appropriate to take which approach.

In the case of the Deepwater Horizon, one of the decisive moments in that process was when workers failed to adequately interpret the results of a failed pressure test. To me there is no excuse for that. That is the place where I think maybe it would have been better if there was a rule that when you failed a pressure test, you stop work, you take certain actions. The workers failed to do that and a disaster ensued. And so I believe there is a time and a place for everything, that there should be some prescriptive requirements, and obviously, I am glad to hear that the agency is considering which, on a case-by-case basis, are appropriate.

Senator HOEVEN. Mr. Milito, how would you respond to that?

Mr. MILITO. Yes, I think the efforts really since 2010 to focus on safety and environmental management systems by both the industry and the Government have really raised the bar considerably. We have the Center for Offshore Safety in place, and they have worked hard to make sure we have independent third parties who come in and audit companies' safety systems, and we have the Government adopting the standards and a lot of the best practices to make sure that when companies are being analyzed are being analyzed based upon their whole safety system. So a lot of this is really outside the scope of this rule when it comes to advancing safety, but a lot has been done since 2010 to truly move in the direction.

With this rule we support a lot of this rule. There are just some provisions that we think we need more time to work with the Government on to make sure that we get it totally right.

Senator HOEVEN. Mr. Salerno, that is a good place for you to respond. You heard his last comment. Please respond to that specifically how you would approach what he is asking, which is saying, look, they can live with a fair amount of this rule, but there are some things they would like you to work with them on. Are you willing to do that?

Mr. SALERNO. We are considering the comments that have come from API and from the—

Senator HOEVEN. You said you are considering the comments before. My question is whether you are still willing to work with the industry in the area of flexibility to try to address some of the concerns that they are raising?

Mr. SALERNO. We have one more meeting scheduled with industry next week. What I would like to—

Senator HOEVEN. You are not going to answer me, are you?

Mr. SALERNO. I cannot tell you specifically how—I cannot announce any decision—

Senator HOEVEN. Are you willing to provide more flexibility in line with industry's request?

Mr. SALERNO. We are considering their comments, sir. That is all I can tell you. I cannot give you any definitive decisions on what we are doing with the comments at this stage. I would be happy to come back and explain it to you when I can.

Senator HOEVEN. Again, I hear Ms. Savitz and her concern about safety and knowing what to do if something happens. I understand that. We all want, obviously, to protect the environment. But I am hearing clearly from industry and you are hearing clearly from Members of Congress that a one-size-fits-all does not work so a good rule has flexibility so that it works in any circumstance and

you can have that flexibility to make sure it works. Frankly, that is ultimately better for safety and the environment as well.

Mr. SALERNO. And I would argue, sir, we do apply flexibility, and that is our agency practice. That is the way we operate. That does not change with this rule.

Senator HOEVEN. Okay, but I want you to listen to the folks sitting next to you. They are asking for more flexibility. You have said you will consider that. I hope you do.

Mr. SALERNO. Yes.

Senator HOEVEN. Thank you.

The CHAIRMAN. Thank you, Senator Hoeven.

This has been a good discussion with the questions going around. I think it was important to acknowledge that since the disaster in the Gulf, industry has stepped forward with safety measures on their own, and of course the regulatory environment has changed a great deal. I think it was also important to get some of that on the record here this morning.

This whole issue of alternative compliance is one that, while it does allow for a level of flexibility as Senator Hoeven has been discussing, I think, too, it also presents that level of regulatory uncertainty. I mean, we certainly saw some of that play out with Shell's exploration or their plans this summer when the permits that they had—they believed to allow them to tee up a work plan that would go without delay. Instead, what we saw was final BSEE approval came July 22 but Shell was not able to commence any operations until August. Then Dr. Rockel mentioned this in terms of the tight time frames that they are dealing with, what many people do not understand is the very, very, very limited season that we have within the Arctic because of the environmental issues that are coming. When the ice is coming, the work plan does not allow you to be in the water.

Shell was looking at a situation that they needed to cease their drilling operations by the 28th of September because their exploration plan required their operations to cease by October 31. So when you think about it, it is less than two months that you are in the water, less than two months. Ask anybody. Senator Cassidy is sitting down there in the Gulf of Mexico and has the benefit of some warm weather. You have got some hurricanes down there, but it is basically 365 days a year.

So when you compress your season into less than two months and recognize that you have got to get the flotilla up there that Director Salerno was talking about in order to put them in place for all of this, it is an operation that simply cannot have additional regulatory uncertainty. They need to know going into it what it is going to look like.

Dr. Rockel, I would like you to speak just a little bit—I do not want you off the hook this morning because when we are talking about the Arctic plan, this is where you clearly have some expertise. I would like to hear from you this morning what you think the Department of the Interior should be doing with the Arctic rule as it stands today. You have mentioned a couple things, the same-season relief well, you mentioned a little bit about the mechanical recovery tools, the relief well requirements.

I have suggested that the Administration needs to look at changing the current ten-year term for offshore leases in recognition of the shortened drill season and just the extra challenges of operating in the region.

Can you give to the Committee some of your suggestions in terms of what Interior should be doing specific to the Arctic plan?

Dr. ROCKEL. Thank you, Senator. I believe that, as I articulated earlier, the same-season relief rig requirement is pretty egregious to the industry. However, keeping it as a performance standard, which would mean you would have it as equivalency, a same-season relief rig equivalency. So if you have the same level of protection, that would be adequate. In other words, promote that regulatory flexibility from a performance standard.

The reason the season is so short, to September 28, was because they were willing to—they were interested in making sure that you could have that same-season relief rig on site. And so if you get rid of the one or allow that flexibility, then you do not have to—you can extend the season, which when you look at the opportunity cost of those days lost, as you point out, over time it can be significant in terms of billions upon billions of dollars in terms of production forgone.

And then the third has to do with the mechanical—having the mechanical for the worst-case discharge, and you want more flexibility. I think what has been successfully accomplished throughout the world is having the operators and stakeholders, including the governments, work on something called a net environmental benefits analysis whereby if there is a release, everybody decides on scene who has the best information what to do, and use all the tools in the toolbox, including in situ burning, including dispersants, making that call depending on the sensitivity of the environment, depending on the weather conditions and the ocean conditions and everything else, in other words, onsite having the best information available to make those decisions.

The CHAIRMAN. Are we taking the lessons learned from other Arctic nations that have exploration opportunity, whether it be Russia, whether it be Norway, are we taking from them some of the best practices and looking to develop an Arctic rule utilizing that?

Dr. ROCKEL. I do not believe we are.

The CHAIRMAN. Why is that?

Dr. ROCKEL. We are more prescriptive, whereas Norway and Greenland and Canada seem to be more performance standard-based. I think one thing that I feel strongly about is the United States needs to be a leader in the Arctic.

The CHAIRMAN. Are we?

Dr. ROCKEL. I do not—it depends who you talk to. But I think what we need to be able to demonstrate is that we can have a safe, reliable Arctic drilling program that other countries can look at and say, yes, they can do it and they are doing it the right way, they are doing it the correct way, they are doing it the safe way.

I am particularly concerned about our friends to the West because, as you well know, the Beaufort arm moves from the Russians down to Alaska, so my big concern about the next blowout is not going to be in the United States. It is going to be there com-

ing into our waters. So I would say that maintaining that leadership position in the Arctic Council with the other countries, using the performance standards, and all regulations ultimately need to be based on sound science, sound engineering, and that is the only way we are going to get—

The CHAIRMAN. Well, Mr. Rockel, I could not agree with you more. I believe that the United States should set those standards. I think working with our regulators in a way that does exactly what Mr. Milito has been talking about, making sure that we are paying attention to safety first but also making sure that there is regulatory certainty that helps to make sure that it is economic as a project. I fear that we have ceded any leadership, any standards-setting in the Arctic right now.

The two players that were front and center in the U.S. Arctic, Shell and Statoil, are no longer there as of the end of this season. Shell's words are they are out for the indefinite future, and Statoil has basically said they have turned back their leases.

For us as leaders in an Arctic environment, which the United States clearly should be doing, I think we are ceding the standards, I think that we are ceding an economic opportunity, and I think that is most unfortunate. Unfortunately, I think the reason that we are now taking this backseat is because of some of the regulatory issues and hurdles that we have faced that have sent operators that did have great interest in the Arctic and put them on an indefinite pause. Let me turn to Senator Cantwell.

Senator CANTWELL. Well, thank you, Madam Chair. You and I definitely agree that the Arctic is a priority for the United States, and you and I certainly agree on the fact that we need an ice-breaker fleet. Dr. Rockel did not mention that, but those other Arctic nations definitely have a very robust fleet.

But my question is back to Mr. Salerno. I wanted to point out we are in a regulatory process that we are finishing up, so you really cannot answer some of these questions in detail, and so I just want to point that out for everybody. As much as you might like to, you really cannot, so thank you for that.

Also, I think we need to remember that what we are trying to do here is change a culture. We did do that to a certain degree by changing the structure within Interior and The Mineral Management Service, but you have to think it is pretty appalling where we were at that time. My question is, people are talking about flexibility in a rule or not being too prescriptive. The real issue is the better the bright line, the better people will be able to understand what it is they have to comply with.

For me, having again sat through those hearings about blowout preventers and the lack of scrutiny that was given to them before, it seems to me that the sharper and crisper the requirements are about testing, about regulation, about oversight of blowout preventers, the better we are going to be. I see you nodding your head, Ms. Savitz. Is that something that you wanted to comment on?

Ms. SAVITZ. Absolutely. I mean, I think the important thing in this type of situation is that we have—you know, if we are not going to stop drilling, which clearly I have not convinced everybody of yet, that we are able to control a loss of well control in a timely fashion, whether—what we have seen is oftentimes that other

intervention methods that we think are going to work do not work. Remember back in 2010 the junk shot and the top hat and all these things we had never heard of before, they did not work. And ultimately, it was the relief well that we were told it would take three months to drill and it did. And so obviously it is something that we want to be prepared to do.

We have a short window of operations in the Arctic, and if the Russians are going to be drilling in the Arctic, I certainly hope they have the capacity to control loss of well control with the relief well. And so I would like to see us be leaders in that context as well.

Senator CANTWELL. Thank you. Mr. Salerno, do you have any general comments about changing culture? Because to me, when you say to people, okay, here are some general rules and some of you can follow this part and some of you can follow that part, it is difficult. The crisper the rule, the brighter the line. Usually what happens within a culture is that everybody understands what that bright line is and they know what they have to comply with.

Mr. SALERNO. Thank you, Senator. No, it is an important point, and that is why we have tackled this as a hybrid approach, to provide the bright line, the target information, the clarity, what it would take to achieve the level of safety, but then also provide a pathway for alternatives. So that is the hybrid nature of it.

To pick up on something Mr. Milito said earlier about safety and environmental management systems, that is a performance-based system. API has their standard. We have adopted that standard in our regulations. But what is interesting, and to your point, Senator, is a lot of the comments that we have received as that rule has been put into place is, gee, you are not specific enough. We do not really quite know how to meet your intent.

So that is why we are really looking at this well control rule as a hybrid and why it is important to provide that degree of specificity certainly for the industry so they have a target but also for the general public so it is very clear what the level of safety envisioned is in this Federal rule.

Senator CANTWELL. Thank you. I certainly hope that we continue to march towards a changing of the culture from where we were at the time of the Deepwater Horizon to something where people understand the safety level that we are going to make a commitment to. So thank you very much.

The CHAIRMAN. Senator Cassidy.

Senator CASSIDY. Thank you, Madam Chair.

First, not that it is apropos of this committee hearing, but it has been mentioned several times, the idea that if the United States leaves its oil in the ground, there will be less CO2 emitted sounds plausible but it is totally absurd. And I say that not to be mean.

But the Iranians want to increase their oil by two million barrels a day. According to the International Council on Clean Transportation and the Carnegie Endowment for International Peace, the Iranians emit two to three times more CO2 equivalence than we do in our Gulf of Mexico rigs. Based on two million a day, if we cede that market to the Iranians, there is going to be 100,000 metric tons of CO2 emitted that will not be if we create those jobs in the United States and produce our own oil. Understanding that, I

know it sounds plausible, but a little bit of examination shows that it is not.

Secondly, Mr. Salerno, again, thinking of those 11 that died and their families, I thank you for your commitment to the safety of these workers. I thank you for that.

So I will continue my line of questions along the lines of specific regulations that may or may not perhaps make it safer. Looking at Mr. Milito's comments but also the comments of others, there is an issue of the drilling margins. You have ascribed a certain weight that has to be achieved. I am told by industry that this never came up in the discussions beforehand and that 63 percent of the wells drilled since 2010 actually would have failed the current regulation on drilling margins.

Also, in Mr. Milito's testimony, he suggests that using this amount of weight may decrease the circulation within the cement, and in so doing, may actually compromise the strength of the cemented well I presume because the weight, again, not allowing circulation, does not allow a complete mixing of everything that is going to make the cement have the highest integrity. So thoughts about that?

Mr. SALERNO. The drilling margin really is an attempt to define a safety margin. It is to make sure you have more pressure inside—

Senator CASSIDY. I accept that, but apparently 63 percent of the wells drilled since 2010 would have failed this test. Empirically, we have a safety margin which seems to be different than the one that you have defined.

Mr. SALERNO. No, I think that ignores, again, the alternative compliance provisions. That is a target. It is—

Senator CASSIDY. I accept that, but if 63 percent of the time they have to look for a waiver of your regulation, that makes a mockery of the regulation, correct?

Mr. SALERNO. No, I would not say so. Again, Senator, we have received a lot of comments, a huge volume of comments on the drilling margin issue. So we are going through all that very carefully.

Senator CASSIDY. I accept that, but there should be some rationale—and again, I am not an engineer. I keep saying that, but it is true. There has to be some rationale, again, if empirically it shows that you can have a drilling margin which is not at what you prescribe and, again, 63 percent of the wells would have failed but they were safely—it is somewhat arbitrary in which the drilling margin was established without kind of a basis in empiricism.

Mr. SALERNO. Well, it is again based on the expertise of our folks in the field who deal with these issues all the time. Again, the idea here is to keep more pressure in the pipe than you have in the formation. If the reverse is true, you have a kick or maybe a blowout.

Senator CASSIDY. I accept that.

Mr. SALERNO. So that is to prevent blowouts.

Senator CASSIDY. Now, Mr. Milito's testimony, though, suggested that every now and then you want to have some mixing within that cement which allows, I gather, a kind of more even permutation of that which would strengthen the cement. It is plausible. I do not

know if it is true, but it is plausible. Mr. Milito, do you have any comments on that?

Mr. MILITO. This is one of the key areas in rule that we have expressed significant concern. The industry actually came out with the standard bulletin on this to make sure that we have a kind of baseline document to make sure we are considering this issue as we move forward and do it safely so that we are maintaining the right amount of pressure in the well in accordance to what the Director said.

So fundamentally what is in the rule is not reflective of what is happening in the Gulf of Mexico, and I think the key point here is why would you move forward with that type of rule when that does not reflect actual operations that are occurring?

Senator CASSIDY. Okay. Next point, one more thing, Mr. Salerno. Industry is saying that you are asking for some technology which has not yet been developed. I think Ms. Savitz suggested this is not true, but they maintain that it is, that the technology does not currently exist to center a cementing pipe before it is sheared, yet, you prescribed that. So if the technology does not exist, how can it be complied with?

Mr. SALERNO. Well, the technology has been developed. You know, we have discussed this with equipment manufacturers. We know it exists. There is also a timeframe for compliance, and this is out, I think—believe seven years on that particular item. So there is plenty of time for that capability to be adequately marketed, installed, and tested.

Senator CASSIDY. Mr. Milito, do you have any comments on whether or not that technology—again, because it seems a question of fact. I have been told both ways.

Mr. MILITO. It comes down to the phasing period. We are in a position where the industry is able to move forward and advance technologies, but we need to make sure we have the appropriate phasing period to make sure we have it available to market to continue Gulf operations.

Senator CASSIDY. I thank you all for your testimony and for being here. I yield back.

The CHAIRMAN. Thank you, Senator Cassidy, and thank you to each of you for your comments here this morning.

Director Salerno, I think you heard clearly from the members of the committee this morning, the hope is that you are looking to all of the comments that have been elicited out there and that the expertise that the industry offers is considered as well.

I appreciate greatly the fact that nobody is saying, hey, we do not need these regulations. Nobody is suggesting that we want anything other than the highest of safety standards to ensure a level of not only safe environmental operation but to ensure that the men and women who are working in this industry are always able to return home at the end of their shift at the end of their day. We care very greatly for them and their families.

But I do think that this is all about finding that balance, and it is not always just a cost-benefit analysis or approach that goes into this. Making sure that we are working with the industry, whether it is to make sure that there is a transition time that is reasonable, whether there is alternative compliance that actually means some-

thing, these are all issues that I hope you take into great consideration as you are moving toward the final rules.

Recognizing again the very distinct issues that we face in the Arctic, you are formulating an Arctic rule so that operators may have some certainty out there. I hope that the rules that you construct are ones that will ensure that we have an industry in our offshore because right now, I think it is fair to say we have none. We had some, and it was just a mere matter of months ago where we had operators that, even given the low prices of oil, were willing to take the financial risk, were willing to make the commitment to what they believed to be enormous prospects, great benefit from an energy security perspective for our country, great benefit for jobs. And they are no longer looking to those prospects at least for this indefinite future.

That does not bode well for my state, and I do not think it bodes well for this country. When we are talking about being that world leader from an energy perspective and from an environmental perspective, we need to have people in the industry that are willing to make that investment. Right now, the Gulf of Mexico is happening, but offshore Alaska is not.

So we need to know that the rules of the road are fair and balanced, and again, with a clear eye toward environmental standards and safeguards because, as we know, the Arctic is a circle up there. Whether it is Russia that may be performing with standards that we do not like, if we have not been up there to help set the standards, it is tough for us to be pushing back too hard in this area. We are all in this together.

I appreciate the comments from all of you and from the committee. With that, we stand adjourned.

[Whereupon, at 12:59 p.m., the hearing was adjourned.]

APPENDIX MATERIAL SUBMITTED

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Questions for the Record Submitted to Mr. Brian Salerno**

Questions from Chairman Lisa Murkowski

Question 1: BSEE’s proposed regulation states: “Based on information provided by industry, all new drilling rigs are already being built, pursuant to the same industry standards BSEE now proposes to adopt (including API Standard 53), and many have already been retrofitted to comply with these industry standards.”

Please provide additional information about these new drilling rigs that are being developed.

- a) How many are being built and how many of those will meet the standards BSEE proposes to adopt?

Response: Although BSEE does not know the exact number of rigs being built, it is our understanding that all rigs currently under construction and destined for Gulf of Mexico projects are being built to comply with API Standard 53, which contains the industry consensus standards concerning engineering and operating practices regarding blowout preventer (BOP) reliability and use. The proposed rule adopts API Standard 53 in full, except for the section that allows an operator to “opt out” of compliance by performing a risk assessment. Thus, rigs currently being built must comply with API Standard 53 in order to comply with the regulations, as proposed.

- b) How many have already been retrofitted?

Response: While it is difficult to ascertain the number of rigs that have been retrofitted thus far, it is our understanding that industry is retrofitting all rigs to comply with API Standard 53, which the proposed rule incorporates. However, BSEE does not track or monitor drilling rig retrofitting and does not know how many rigs have already been retrofitted.

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- c) Will additional upgrades be required to comply with BSEE regulations? If so, how much would they cost?

Response: If a rig is built or retrofitted to comply with API Standard 53, and the operator does not exercise the “opt out” provision in the standard, the rigs will meet the requirements of the BSEE regulation, as proposed. The well control rule has not yet been finalized, so BSEE cannot comment on any deviations between the final rule and industry standards, or whether additional upgrades will be required to comply with the final rule.

Question from Senator Maria Cantwell

Question 1: At the hearing there was much discussion about the balance of performance-based regulations that allow more compliance flexibility but can make enforcement a challenge versus prescriptive regulations that are easier to enforce but can stifle innovation and even lead to unintended safety consequences. Please explain how your agency is currently balancing flexibility and specificity as it applies to the Well Control Rule. What issues associated with Well Control are more amenable to performance-based standards and what are best kept very clear-cut? You mentioned during the hearing and in response to a question from Senator Cantwell that BSEE received requests for clarification on the Safety and Environmental Management Rule, a performance-based rule, suggesting that the right balance may not have been achieved and that more specificity may have been useful in that case. Can you please explain further?

Response: BSEE currently balances flexibility and specificity as it applies to the Well Control Rule by setting out both prescriptive and performance-based requirements while also maintaining provisions that allow for alternative compliance. Well control is a complex aspect of offshore drilling that involves a multitude of processes, operations, and

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equipment. BSEE addresses this complexity by employing multiple approaches to regulation including specifying prescriptive requirements, promulgating performance-based regulations, and establishing baseline requirements or minimum standards of performance. Also, many of the industry standards, such as API Standard 53, that are incorporated by reference, contain both prescriptive and performance-based criteria.

Alternative compliance is another way in which BSEE balances flexibility with specificity. The current regulations have a provision that allows OCS lessees and operators to obtain approval to use any alternate procedures or equipment that “provide a level of safety and environmental protection that equals or surpasses current BSEE requirements” (30 C.F.R. § 250.141). In addition to this general provision for alternative compliance, the proposed rule incorporates several provisions that reinforce the ability of operators to apply for an alternative means of compliance with the regulations:

- Proposed § 250.701 – Expressly allows use of alternate procedures or equipment (for all Subpart G requirements), if approved under § 250.141 and discussed in the Application for Permit to Drill (APD)/Application for Permit to Modify (APM)
- Proposed § 250.702 – Allows operators to apply for departures, under existing § 250.142, from the Subpart G well control requirements, provided the departure is discussed in the APD/APM
- Proposed § 250.720(a)(2) – Allows for the use of alternative procedures or barriers (instead of the specifically required barriers) to secure a well, if approved by the District Manager under § 250.141
- Proposed § 250.730(d)(1)-(2) – Allows operators to use BOPs manufactured under a different quality assurance program than API Spec. Q1, provided that the operator requests and BSEE approves such an alternative

The proposed rule also emphasizes that operators may apply for alternatives to compliance with the section of API Standard 53 for blowout preventer (BOP) shearing of drill pipe under 30 C.F.R. § 250.141.

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The Safety and Environmental Management Systems (SEMS) Rule is a non-traditional, performance-based rule.¹ Following the issuance of this performance-based rule, many in industry raised concerns about the lack of specific guidance on how to comply with the requirement. In fact, industry issued a compliance-based checklist for its members to use to satisfy SEMS obligations. BSEE has been working with industry to move away from this compliance-driven document toward the use of more performance-based approaches to reinforce the concept that safety must be managed continually and measured in terms of outcomes.

¹ 30 C.F.R. § 250.1900 *et seq.*



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December 15, 2015

Honorable Lisa Murkowski
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Honorable Maria Cantwell
 Ranking Member, Senate Committee on Energy and Natural Resources
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SUBJECT: API Answers to Question for the Record, Senate Committee on Energy and Natural Resources, Hearing Pertaining to the Well Control Rule and Other Offshore Regulations

Chairman Murkowski and Ranking Member Cantwell,

Thank you again for the opportunity to testify before the committee on the Well Control Rule and other offshore regulations. The following answer is provided to the question for the record that I received following the hearing. Please do not hesitate to reach out to me should you have any follow-up questions. Our industry remains committed to safe and environmentally responsible offshore operations and we stand ready to work with the Department of the Interior to ensure that any changes to regulatory regime truly advance safety.

Question from Senator Maria Cantwell

Question 1: During the hearing, you stated that API doesn't oppose the Well Control Rule, but that you just want to make sure we get it right. API has raised several concerns regarding various aspects of this rule. Yet safety is also a key priority. Given the timeliness of finalizing this rule already over 5 years after the Deepwater Horizon explosion, would API support finalizing this rule if it allowed for things like alternative compliance of drilling plans, performance-based requirements for BOP designs, and rolling inspections of drilling equipment components such that 100% of the BOP would be inspected every 5 years? Please clarify any lingering concerns API members may have if these three areas were addressed in the final Well Control Rule.

Response: 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. Working together, we can ensure that BSEE develops a final rule that is ultimately both workable and effective.

API and our members do not support an arbitrary prescriptive drilling margin. A prescriptive drilling margin that is based only on mud weight and leak off test criteria may actually reduce the safety of drilling operations as the operator may not be able to choose the mud density best suited for the interval based on drilling and geological parameters. A lower mud weight may have to be used to meet the proposed requirement. The resulting reduction of the mud weight overbalance to the formation could create wellbore stability problems or potentially allow undesired influx of formation fluid into the wellbore. This adds unnecessary downhole drilling risk to the well construction process, possibly impacting personnel, environment and facilities. The current risk-based approach to managing drilling margin (in combination with existing regulatory oversight) has been demonstrated to safely drill wells having narrower drilling margins than the margins that would be allowed by the proposed rule. Alternative compliance is not a satisfactory approach, especially when the majority of the operations would likely fall outside of the prescriptive regulatory requirements and thus fall under an alternative compliance process. The industry relies upon a regulatory regime that promotes certainty, predictability and consistency. A rigid drilling margin requirement would run directly counter to each of those principles.

Industry, with input from BSEE, developed API Bulletin 92L *Drilling Ahead Safely with Lost Circulation in the Gulf of Mexico* (API 92L) which summarizes best drilling practices when drilling wells with narrow drilling margins. API 92L addresses BSEE's concern to document and codify safe drilling margin practices and reduces the need for more prescriptive drilling margin requirements. Therefore, this document should be incorporated by reference into the final rule, in lieu of more stringent drilling margin regulations, for operations where equivalent site-specific lost returns procedures have not been developed. This is an alternative to more prescriptive regulations. Through well-established operational procedures, hundreds of wells with margins smaller than that required in the proposed rule have been drilled successfully and safely.

API Standard 53 *Blowout Equipment Systems for Drilling Wells* (API 53) was developed using the API ANSI accredited standards development process based on openness, balance, consensus and due process, with BSEE participation. The current (4th) edition was published three years ago, in November 2012, and is the product of two-plus years of subject matter experts' work and has now been in use for 3 years. Industry has accepted, adopted and is moving towards complete adherence to API 53. Industry fully supports incorporation by reference of API 53, in its entirety. Our concerns are related to those requirements that deviate from the document. Performance-based requirements for BOP designs and rolling inspections of BOP equipment every 5 years that are consistent with API 53 are supported by industry.

The industry also remains very concerned about the real-time monitoring requirements, the overbalanced packer fluid requirements, the mud weight during cementing requirements, the accumulator bottle requirements, the ROV panel requirements, and other requirements that

deviate from API 53 in the proposed rule. The government has not established that any of these proposed changes will enhance safety.

Thank you again for the opportunity to testify and to provide responses to these questions.

Best regards,

A handwritten signature in black ink, appearing to be "W. J. ...", written in a cursive style.

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**Question for the Record Submitted to Dr. Mark Rockel
from Senator Maria Cantwell**

Question 1: In your testimony, you state that other countries have adopted elements of performance-based regulations for drilling requirements, well control, independent verification, and oil spill response. At the hearing and in response to a question from Senator Cantwell, Director Salerno stated that the Safety and Environmental Management Systems Rule, a performance-based rule, generated many comments that the rule wasn't specific enough and that industry had struggled to know how to meet the objectives of the rule. Director Salerno discussed how BSEE worked to achieve a better balance between performance-based and prescriptive approaches in the Well Control Rule. In the interest of achieving the right balance between flexibility and specificity and taking advantage of the experience of others, please summarize how Denmark, Canada, and Greenland have used performance-based regulations to address the issues you raise in your testimony. Please highlight how these countries achieved a balance between flexibility and specificity, performance-based and prescriptive.

RESPONSE: Senator Cantwell thank you for the opportunity to respond to your question. The United States (Alaska), Canada, Russia, Norway, Denmark (via Greenland, which is a member country of the United Kingdom of Denmark) Finland, Sweden, and Iceland all have claims to resources found in the Arctic Outer Continental Shelf (OCS).

While there is little disagreement over the ecological and societal value of the natural resource that is the Arctic, there is significant divergence between these nations as to how best protect that resource, while still encouraging meaningful development, which also has economic value, of those assets.

There are a number of companies that are currently conducting (or have conducted in the past) exploration and drilling activities in Outer Continental Shelf (OCS) waters of Norway, Canada, Greenland, Russia and the United States. Norway has the longest history of supporting and regulating exploration in the OCS (with first wells being scoped in the early 1970's), and the most diverse history of experimentation and evolution of regulatory regimes and approaches to govern and manage these activities.

The single event of the 2010 Deepwater Horizon Macondo spill in the US Gulf of Mexico has resulted in a frenzy of publicity and effort on the part of various US based and international advocacy groups calling for tighter, more restrictive regulation and more stringent regulatory oversight of oil and gas exploration and development. In

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contrast, the Norwegian response to what can arguably be considered a greater number, and a more catastrophic series of incidents (the blow-out at the Bravo platform (1977), the capsizing of the Alexander Kielland platform (1980) and the gas explosion and burning of the Piper Alpha platform (1988) has been exactly the opposite (Lindøe, 2011 pg. 1. Deepwater Horizon, pg. 69)¹.

Since the 1980's Norway has been working at developing a coherent, integrated legal framework for regulating health, safety and environment in the conduct of oil and gas operations. Rather than developing specific protocols, procedures, conditions and constraints, the Norwegian approach has been to develop and codify minimal standards and functional requirements, placing the burden of how those thresholds and benchmarks are met on the producers. The focus has been on promoting self-regulation by operators by directly requiring each operator to develop and apply an "internal control" systems for reducing risks and preventing and responding to accidents, reflecting the "sound health, environment and safety culture." (Lindøe, 2011 pg. 3)².

Norway is not unique among Arctic states in adopting risk and performance based approaches to permitting and regulation of activities in the Arctic OCS. Denmark, Canada and Greenland have all adopted elements of performance based regulation for: drilling requirements, well control, and independent verification and oil spill response. Although not an Arctic OCS nation, Australia has also adopted a risk based approach to legislation governing offshore exploration and production.

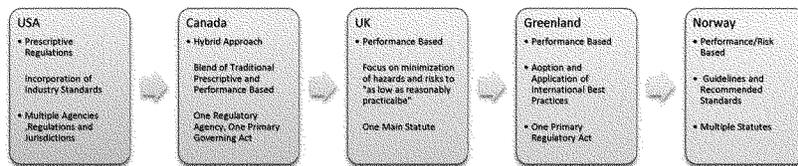
As part of an "Arctic Offshore Drilling Review" conducted in 2011 the Canadian National Energy Board (the governing body charged with regulating offshore oil and gas drilling and production) commissioned a comparative analysis of the regulatory regimes of four countries with Arctic offshore drilling operations³. Overall, the analysis conducted by the Pembina Institute found that only the United States relies almost exclusively on prescriptive approaches to regulate offshore drilling and production. The U.K., Greenland and Norway utilize an almost entirely risk/performance based set of protocols, while Canada employs a hybrid of the two.

¹ Lindøe, P.H., M.Baram & G.S. Braut. Empowered Agents or Empowered Agencies? Assessing the Risk Regulatory Regimes in the Norwegian and US Offshore Oil and Gas Industry. Paper at ESREL Conference, 19-22 Sept. 2011 and Deepwater: The Gulf Oil Disaster and the Future of Offshore Drilling, Report to the President of the United States, National Commission on the BP Deepwater Horizon Oil Spill & Offshore Drilling, January 2011.

² Ibid. Lindøe

³ Comparing the Arctic Offshore Oil and Gas Drilling Regulatory Regimes of the Canadian Arctic, the U.S., the U.K., Greenland and Norway. Executive Summary. The Pembina Institute. 2011 www.pembina.org/pub/2227

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The table below provides an illustration of the different approaches applied to key areas of concern as outlined in the report.

Categories	USA	CANADA	UK	GREENLAND	NORWAY
	Mixed	Mixed	Performance	Performance	Performance
DRILLING					
Well Design	Plan Submission/Review	Regulations	Meet conditions to "minimize risk, ensure safety and prevent fluids from escaping"	Detailed Program Submitted for Review	No Specific Requirements
Casing and Cementing	Regulations	Safety Goals	Same	Detailed Program Submitted for Review	No Specific Requirements
Drilling Procedures	Plan Submission/Review	None Specified	Same	Detailed Drilling Plan Submitted for Review	No Specific Requirements
ESD	Regulations	Regulations	None Specific	None Specific	One Should Exist
DPS	None Specific	Regulations	None Specific	None Specific	General Regulations governing how and when it works
WELL CONTROL					
BOP	Regulation- Must Use BOP, diverters and safety valves	Regulation for some operations	Included as part of well plan, recommended	Submit Information- No Specific Requirement	Must have intervention equipment, safety valves

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			use of diverters and safety valves		diverters
Remote Operation of Well Control	Regulation- Must Be Able to Control Remotely	No Specific Requirement	No Specific Requirement	No Specific Requirement	Must be able to control remotely
Well Relief Plans	Regulation- Must have second drilling rig	Must Develop Plan- second rig not mandatory	Must Show Plans for timing, resources and design-	Must Develop Plan- second rig not mandatory	Must be able to drill a relief well
OIL SPILL RESPONSE					
Level of Response Planning	Worst Case Scenario	Not Specified	Risk of Worst Case Scenario	Not Specified	Risk Based.
Operator Plan	On hand, including testing and monitoring	On hand, including testing and monitoring	On hand, regular testing, assumes minimum response time	Part of Environmental Assessment, no testing required, minor spill response capability "on hand"	Risk Based Plan- reviewed and tested annually
Regional & National Plans	Must Have	Must Have	Must Have	Program Exists	Must Have
Regulatory Intervention	National Government can Intervene	NEB can Intervene	National Government can Intervene	Limited National Intervention	National Government can Intervene

Performance Based Approaches and the Current Administration

The environmental and social protection laws that form the basis for regulation and environmental protection in the United States (Clean Air Act, Clean Water Act etc.) are in fact a set of highly prescriptive "command and control" style regulations, with established decision criteria, time tables and standards/mandates. They were designed to be punitive in nature and, by definition, have resulted in the creation of an adversarial relationship between the regulator and the regulated.

President Ronald Reagan took the first steps to move government away from punitive, prescriptive approaches, towards ones that advocated a more "performance based"

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approach to regulation.⁴ President Clinton continued this emphasis on understanding and balancing the costs and benefits of regulation⁵ and supported the trend towards performance based approaches to regulation. During his tenure, the results of three major initiatives to “re-think” regulation were released, all calling for a re-vamp of EPA and the adoption of a performance based approach to regulation and environmental protection.⁶

The emphasis on performance based approaches had continued through the second Bush administration and on into the current Obama administration, most recently with the signing of Executive Order 13563 in January 2011, which reaffirmed the mission of the Regulatory Working Group to “serve as a forum to discuss, coordinate, and develop a common understanding among agencies of U.S. Government positions and priorities with respect to: a) international regulatory cooperation activities... b) ... significant, cross-cutting international regulatory cooperation activities, such as the work of regulatory cooperation councils; and c) the promotion of good regulatory practices internationally, as well as the promotion of U.S. regulatory approaches, as appropriate”⁷

As it relates specifically to the oil and gas industry, the 2011 report to the President “Deepwater: the Gulf Oil disaster and the Future of Offshore Drilling” prepared by the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling makes several, specific references to the need to adopt risk/performance based approaches to regulating exploration and development. In particular: on pages 251 and 252:

“neither the industry’s nor the federal government’s approaches to managing and overseeing the leasing and development of offshore resources have kept pace with rapid changes in the technology, practices, and risks associated with the different geological and ocean environments being explored and developed for oil and gas production.....”
and

“Government agencies that regulate offshore activity should reorient their regulatory approaches to integrate more sophisticated risk assessment and risk management practices into their oversight of energy developers operating offshore. They should shift their focus from prescriptive regulations covering only the operator to a foundation of

⁴ Exec. Order No. 12,291, 3 C.F.R. 127 1982, which requires agencies to evaluate new regulations, weighing the overall benefit that they would provide to society against the costs they would impose not only on society, but on the regulated. Exec. Order No. 12,498, 3 C.F.R. 323 (1986) which requires agencies to submit an annual regulatory plan and to adhere to cost-benefit principles.

⁵ Exec. Order No. 12,866, 3 C.F.R. 638, 639 (1994), and Exec. Ord. No. 12,866, 3 C.F.R. 638(1994) requiring agencies to assess all costs and benefits of regulatory alternatives.

⁶ Enterprise for the Environment, *The Environmental Protections System in Transition: Toward a More Desirable Future* (1998), chaired by former EPA director William Ruckelshaus et al), *Thinking Ecologically: the Next Generation of Environmental Policy* (Chertow & Etsy 1997) and National Academy of Public Administrations “Resolving the Paradox of Environmental Protection: An Agenda for Congress, the EPA and the States (1997) as referenced in “Steinzor, Reni I. Reinventing Environmental Regulation, Back to the Past by Way of the Future. *Environmental Law Reporter*. 28 ELR 10361. 1998.

⁷ Exec. Order No. 13,563 76 FR 3821 (2011).

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augmented prescriptive regulations, including those relating to well design and integrity, supplemented by a proactive, risk-based performance approach that is specific to individual facilities, operations, and environments. This would be similar to the “safety case” approach that is used in the North Sea” and finally on page 254

“The United States should lead in the development and adoption of shared international standards, particularly in the Gulf of Mexico and the Arctic. Transparent information and data sharing within the offshore industry and among international regulators is critical to continuous improvement in standards and risk management practices...

There are a number of international initiatives that are in process, or have recently been completed to capture and standardize best practices for exploration and drilling in the Arctic OCS. These include:

- the upcoming decisions and recommendations from the Norwegian Petroleum Safety Authority (PSA) regarding drilling north of the 74.5 N and in the Barents Sea (due Sept/Oct 2014);
- the development of the new European Union Offshore Safety Directive (Directive 2013/30/EU) which went into effect 18 July 2013 and will be transposed into the national laws of EU member states by July 2015;
- the Canadian National Energy Board, Environmental Protection Plan Guidelines (2011) and National Energy Board, Safety Plan Guidelines (2011)
- the Feb 2014 Arctic Offshore Oil and Gas Guidelines: Systems Safety Management and Safety Culture. Prepared by the Protection of the Arctic Marine Environment Working Group under the auspices of the ARCTIC COUNCIL;
- the *January 2014 Implementation Plan for National Strategy for Arctic Region*
- the *May 2013 National Strategy for Arctic Region* National Strategy for the Arctic Region,
- The North-East Atlantic Environment Strategy of the OSPAR Commission for the Protection of the Marine Environment of the North-East Atlantic 2010–2020 (OSPAR Agreement 2010-3).
- ARCTIC COUNCIL. ARCTIC OFFSHORE OIL AND GAS GUIDELINES. 2009



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16 July 2015

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

Via – Regulations.gov

Re: *Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control* [Docket No. BSEE-2015–0002; RIN 1014-AA11]

To whom it may concern:

The International Association of Drilling Contractors is a trade association representing the interests of drilling contractors, onshore and offshore, operating worldwide. Our membership includes all drilling contractors currently operating mobile offshore drilling units (MODUs) in the areas subject to the jurisdiction of the United States.

IADC and our members have joined with the American Petroleum Institute (API), 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 (USOGA) in developing a comprehensive response (“Joint Response”) to the proposed rule, which is being separately submitted to the rulemaking docket. IADC fully supports the comments offered therein.

The purpose of this letter is to complement and supplement the Joint Response.

As a trade association, IADC’s purpose is to advance drilling and completion technology; improve industry health, safety, environmental and training practices; and champion sensible regulations and legislation which facilitate safe and efficient drilling. It is in this capacity that IADC provides this response to the 17 April 2015 proposed rule (80 FR 21503 *et seq*) to revise and add new requirements to regulations to, *inter alia*: Implement recommendations resulting from various investigations of the Macondo incident, revise blowout preventer (BOP) requirements, incorporate various industry standards; and revise existing regulations in the areas of well design, well control, casing, cementing, real-time well monitoring, and subsea containment.

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The views and comments in this letter are offered without prejudice to comments that may be offered individually by our members.

Five years ago, a tragic blowout engulfed the Macondo well – devastating the Gulf of Mexico, the global drilling industry and, indeed, our colleagues onboard the *Deepwater Horizon*. The magnitude of the blowout and resulting spill brought about a heightened awareness of how one incident, on one well, can have far-reaching consequences – nearly wiping out the industry’s social license to operate. It was a stark reminder of our industry’s responsibility to protect the lives of its people and the environment in which we operate.

Since that disaster, drilling contractors, operators, service companies, and industry organizations like IADC have embarked individually, in keeping with each organization’s respective areas of particular influence and expertise, and jointly, to make sure such events never happen again.

Relevant to this proposed rulemaking, initiatives which have been undertaken by IADC include, *inter alia*:

- An immediate review of IADC’s *Health, Safety and Environment Case Guidelines for Mobile Offshore Drilling Units*, with a revised edition issued in December 2010 to address gaps identified in the immediate aftermath of the incident in the guidance provided for safety and environmental management systems. Two subsequent editions have been issued in the spirit of continuous improvement. The Guidelines are made available, without charge, on the IADC website.
- The launch of the IADC Knowledge, Skills, and Abilities (KSAs) project, with a database comprising core competencies for more than 70 rig-based positions, the IADC KSAs, available without charge on the IADC website, provides a tool for the industry to demonstrate their personnel’s qualifications.
- The establishment of the Well Control Institute (WCI), as an independent subsidiary of IADC, with the goal of establishing itself as the most influential and competent body for dealing with the priorities that are outstanding for improving well control.
- In May of this year, IADC unveiled WellSharp™, the drilling industry’s new well control training and assessment program. WellSharp™ was developed through a collaborative, industry-wide and industry-led effort to redefine well control training. It emphasizes rigorous training for every person with well control responsibilities, whether office-based or rig-based. WellSharp™ is designed to ensure that the industry’s workforce has the training and knowledge needed to both prevent incidents and respond swiftly and appropriately to unforeseen incidents.

A newer joint effort that is still under way is the BOP Reliability and Performance Information Database. IADC and the International Association of Oil and Gas Producers (IOGP) are collaborating on this joint industry project (JIP) – involving contractors, operators and service companies – to develop a BOP performance database to improve subsea BOP systems and related operating procedures. The JIP will be based on a platform established by the Subsea BOP Executive Group, more commonly known as the “Group of 7.” This consortium of offshore drilling

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contractors was motivated by the recommendations for reporting of equipment malfunctions and failure contained in API Standard 53, Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition (API 53), to construct a system that will form the basis of the an ongoing performance database. It will track and report failures of BOP equipment and eventually will be useful for tracking BOP component reliability trends.

More broadly, the Macondo/Deepwater Horizon incident provoked the assembly of the largest gathering of well control subject matter experts in history to come together to develop an understanding of the causes of the incident, identify mitigating measures, and develop appropriate standards and guidelines for the general improvement of safety in the drilling industry. A primary focus of these efforts was the API standards program. IADC has consistently and vigorously urged its members to provide subject matter experts to serve on API's standards committees, has directly supported these efforts with IADC staff, and has supported jointly-administered standards work groups.

IADC offers the following comments to complement those provided in the Joint Response:

Proposed imposition of requirements beyond those addressed in API 53

In general, those provisions of the proposed rule that would prescriptively impose requirements which exceed the provisions of API 53 are unnecessary and will not improve safety. Particular concerns include:

- The proposed rule's demand for larger, heavier and more complex BOP stacks:
 - The additional accumulator requirements are confusing. During deliberations to prepare the Joint Response, the industry's subject matter experts could not reach a common understanding of the intended requirements of the proposed rule. There were significantly different views regarding the redesign of the stack needed to achieve compliance. Clearly, BSEE needs to find an avenue for technical discussions on this issue before moving forward with the regulations.
 - An unintended consequence of the demand for greater accumulator volume could be the removal of other BOP components with a concomitant reduction in redundancy and well control options.
 - There are physical and technical constraints on available space for installation of additional or larger capacity equipment.
 - It appears that the intent of the rule with respect to enhanced remotely operated vehicle (ROV) intervention capability could be met without doubling the number of receptacles and associated fittings, as would be required by the prescriptive language of the proposed regulation.
 - The effective dates need to be adjusted to provide sufficient lead times for engineering, installation and testing of equipment in consideration of the industry's capacity to respond.

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- The proposed requirement for complete breakdown and detailed physical inspection of the BOP and every associated system and component must be performed every 5 years with no option for this to be performed in phased intervals. (§ 250.739(b)):
 - There is no compelling reason to believe that the proposed rule’s quinquennial inspection scheme will produce a result superior to that which will result from adherence to the periodic maintenance and inspection requirements of API 53.
 - Rather than allowing inspections to be conducted as operations permit, thereby reducing downtime, the rule would require that rigs be taken from service for an extend period for well control equipment tests. This not only incurs significant costs, it could result in a modification of contracting practices.

Undue prescription and the stifling of the introduction of new technologies

The proposed rule is unduly prescriptive. Such prescription can cause confusion and, due to delays inherent in the rulemaking process, such prescription often serves to both memorialize and mandate the use obsolete technology and imposing burdens on both BSEE and industry to subsequently obtain relief though 30 CFR §§250.141 or 250.142. The Joint Response identifies numerous instances where this is the case. To illustrate:

- Apparently not satisfied with the language in API 53 requiring that all subsea stacks “have fully redundant control pods”, the proposed §250.734(a)(2) prescriptively dictates that a subsea BOP must have a “dual-pod control system” – proscribing systems with more than two pods. Why?
- The proposed § 250.736(d)(1) requires the use, “during all operations,” of “a kelly valve installed below the swivel” even though kellys are no longer in widespread use in offshore drilling operations. Is this a drafting oversight, or does BSEE really intend that such equipment be used?
- The proposed § 250.711 works at cross purposes. It (appropriately) requires that well-control drills “familiarize personnel engaged in well operations with their roles and functions so that they can perform their duties promptly and efficiently.” However, it goes on to state: “The same drill may not be repeated consecutively.” Does BSEE really intend to prohibit the repetition of a drill to achieve a satisfactory outcome and reinforce learning objectives when the initial outcome was unsatisfactory?

For several years, IADC and API have been cooperating in the development of standards for managed pressure drilling. The prescriptive nature of the both the present and proposed regulations serve to stifle the introduction and employment of this technology in the United States.

The need for further discussion and dialog

The Joint Response provides detailed comments and recommendations regarding the proposed regulatory text. Further discussion and dialog are needed to assure both that regulations are

developed in the most cost-effective manner to achieve the overall regulatory objective, and that there is a common understanding of the specific technical objectives of the rule prior to committing significant resources towards the rule's ultimate implementation.

Inadequacies in the Initial Regulatory Impact Analysis (RIA)

The Initial RIA accompanying the proposed rule entirely fails to recognize the significant burden that implementation of the proposed rule would place on drilling contractors and significantly under-estimates the costs of implementation.

- The RIA makes no attempt to differentiate among the organizations (e.g., oil companies, service contractors, equipment manufacturers, or others) that will bear the costs of implementation. Significant costs associated with blowout preventer system upgrades, inspections and verifications, and maintenance will be borne by a limited number (± 13) rather than the 130 entities presumed in the RIA.
- The RIA fails to consider the impact of “hard-points” in the regulatory implementation scheme. This becomes particularly acute when significant demands are placed on the engineering and manufacturing capacity of the industry and inspection service providers. Lead times simply render infeasible proposed equipment and training requirements proposed for implementation 90 days after the issuance of the final rule. Implementation tied to submission of APD and APMs compresses implementation timelines for changes proposed with an effective date 5-years after issuance of the final rule, particularly in consideration that such changes will likely need to be affected prior to even offering the rig for a contract after the effective date.
- The RIA fails to consider that the incorporation by reference of ANSI/API Spec. 16A, Specification for Drill-through Equipment, Third Edition, June 2004, ANSI/API Spec. 16C, Specification for Choke and Kill Systems, First Edition, January 1993, and API Spec. 16D, Specification for Control Systems for Drilling Well control Equipment and Control Systems for Diverter Equipment, Second Edition, July 2004, will effectively prohibit use of equipment covered by these specifications manufactured prior to the specifications' effective dates. No costs have been attributed to the upgrade or replacement of non-conforming equipment.
- The 10-year analysis period employed for the RIA inappropriately minimizes the costs associated with those elements of the rule that impose recurring costs. The change to the net present value of recurring costs diminishes as the analysis period is extended, but a 10-year window is inappropriate.
- The RIA inappropriately adjusts the “baseline” for proposed elements of the regulation which BSEE has imposed without regulatory due process, e.g., Global Positioning System (GPS) for Mobile Offshore Drilling Units, BSEE NTL 2013-G01 imposed by and earlier NTLs.
- While IADC would acknowledge that calculation of costs associated with possible effects on the worldwide employment of mobile offshore drilling units is not feasible, IADC would expect that the RIA at least acknowledge that, because the rule proposes requirements significantly in excess of the industry norms (as established by API 53 and its normative references), there are likely to be disruptions in the market associated with:

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- Upgrading of rigs presently operating outside of U.S. jurisdiction in order for them to be offered for contracts on the U.S. OCS;
- Continued commercial acceptability, outside the U.S., of rigs that have been upgraded for compliance with U.S. requirements due to, among other things:
 - The increased mass of the BOP stack and its potential incompatibility with wellhead systems outside the U.S.; and
 - The increased operating, inspection and maintenance costs which would be necessary to retain eligibility to return to the U.S. market.

Proposed use of BSEE-approved Verification Organizations (BAVOs)

If BAVOs are to be institutionalized by the final rule, consideration needs to be given to the following:

- Major aspects of the rule’s implementation are entirely dependent upon the prior approval of a sufficient number of BAVOs, with sufficient resources, to provide the BAVO verifications and certifications required to accompany the submission of APDs and APMs. Implementation dates need to be made contingent upon BSEE’s approval of an adequate number of BAVOs to perform the required services.
- No provisions of the proposed rule expressly address the oversight of BAVOs, or the possible need for withdrawal or revocation of approval. Such provisions should be added.
- There is no requirement for BAVOs to operate under a quality system with either BSEE or independent third-party audits. Such provisions should be added.
- BAVOs will be charged with interpretation of the BSEE regulations, such industry standards as are incorporated by reference, and recognized engineering practices. However, no indication is given as to how BSEE would provide the BAVOs with the guidance and oversight necessary for rendering such interpretations. Just as there is a need for consistency among BSEE Regional and District offices, there will be a need for consistency among BAVOs. A transparent system for provision of interpretations will be needed.
- Neither is there any means articulated for how those who may be adversely affected by a BAVO’s decision deriving from such an interpretation can appeal the BAVO’s decisions to BSEE. An appeals process will be required.

IADC offers the following comments to complement those provided in the Joint Response:

Economic analysis – Industry costs v. impacts on contractors

As noted above, the rule, and the associated economic analysis, fail to acknowledge that individual contractors, not “the industry” and not operators (*i.e.*, oil companies) will bear many of the costs associated with implementation of the rule. Contractors may be able to recoup some of these costs in accordance with the terms of the individual rig contracts, or (over time) through increased rig rates, but this is by no means guaranteed.

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Implementation of the rule has the potential to disrupt normal contracting practices. Operators will understandably prefer to not contract for the services of a rig where the rig may need to be taken out of service in order to upgrade equipment as provisions of the rule are phased-in (e.g., as with the proposed upgrades to the BOP system that would be required by §250.734(a)(1)), or during periods when significant compliance costs or operational uncertainties may be incurred (e.g., as with the quinquennial breakdown and inspection of the BOP system and associated components proposed §250.739(b)).

As noted above, the retrospective application of API Spec. 16A, API Spec. 16C, and API Spec. 16D to existing equipment would effectively proscribe the use of such equipment and render it obsolete. If such manufacturing specifications are to be incorporated by reference:

- It must be done in a manner that is tied to the date of manufacture of the equipment subject to the incorporation by reference, similar to the approach that BSEE is taking with respect to its incorporation by reference of API Specification 2C for offshore pedestal-mounted cranes (RIN 1014-AA13), where existing equipment is either “grandfathered” or retrospective application of additional requirements to existing equipment are addressed through the formal rulemaking process.
- To facilitate technically justifiable deviations from the specifications, a means must be provided for equipment manufacturers or owners to obtain direct access to BSEE approval authorities for acceptance of alternatives or departures under 30 CFR §§250.141 and 250.142.

For this rulemaking, these concerns would be obviated if these specifications were not incorporated by reference, but were to remain normative standards within the context of API 53.

In order to assess the cost-effectiveness of the proposed regulations as the economic analyses is further developed, it will be necessary to differentiate between those rigs that employ surface stacks (jack-ups) and those employing subsea stacks (floaters). These are effectively two different markets. Not to minimize the economic effects on floaters or platform rigs, but given already fragile market conditions, the effect of implementing the proposed rule will be acute for the jack-up market. Unlike many international areas, very few jack-ups in the U.S. are under term contracts, and the well-to-well nature of most contracts makes it easy for many rigs to be released very quickly. For example, Rigzone Data Services has reported that:

- On 2 June 2015, there were 20 marketed jack-ups in the U.S. Gulf of Mexico – in contrast to 34 which were marketed in November 2014.
- Of the marketed jack-ups only ten were under contract on 2 June – in contrast to 21 which had been under contract in November 2014.
- The leading edge day rate for a 300-ft, independent-leg cantilever jack-up (IC) was \$130,000 in November 2014 but had fallen to \$85,000 in June 2015.

IADC understands the difficulty in accounting for the diversity of impact on contractors in an economic analysis, but such impacts should at least be acknowledged. IADC has urged its

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members to provide relevant cost information directly to BSEE, asking that it be treated as confidential business information.

Lack of privity

In order to be qualified to operate on the U.S. outer continental shelf, contractors are being required to make substantial investments in new and/or upgraded equipment without being afforded access to the agency to obtain departures or acceptance of alternatives. For example:

- Most BOP equipment is purchased by contractors. The proposed §250.730(d)(1) would allow for consideration of an alternative program (to API Spec. Q1) for the manufacture of BOP equipment, but the path for such an approval does not appear to be available to contractors except through the sponsorship of an operator. Even if such approval is obtained, the accepted alternative would not appear to be binding on other District Managers or Regional Supervisors. (The proposed rule refers to approval under § 250.141, which is granted by District Managers and Regional Supervisors, but requires that the request be submitted Chief, Office of Offshore Regulatory Programs.)
- The existing §250.141, and the proposed §250.701, allow for consideration of use of an alternative or updated equipment specification (e.g., API Spec 16D, third edition, when issued) and for departures. The path for such an approval is not available to contractors except through the sponsorship of an operator. Even if so obtained, the accepted alternative would not appear to be binding on other District Managers or Regional Supervisors or, under the proposed §250.701, for subsequent use of the equipment under a new Application for Permit to Drill (APD) or Application for Permit to Modify (APM).
- A similar situation exists with regard to the existing §250.142, and the proposed §250.702, in the process for obtaining departures.

There is limited incentive for an operator to serve as an advocate for an equipment manufacturer or contractor in obtaining BSEE “approval” for departures or acceptance of alternatives. Indeed, the need for such departures or alternatives, even when fully technically justified, could become an issue during commercial negotiations.

Technical Barriers to Trade

The World Trade Association’s Technical Barriers to Trade (TBT) Agreement, to which the U.S. is a party, aims to ensure that technical regulations, standards, and conformity assessment procedures are non-discriminatory and do not create unnecessary obstacles to trade. The TBT Agreement strongly encourages members to base their measures on international standards as a means to facilitate trade, recognizing the right of WTO members to implement measures to achieve legitimate policy objectives.

The elements of the proposed rule clearly and significantly exceed international standards (e.g., as represented by API 53) in proscribing equipment requirements for blowout prevention

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equipment systems. When implemented, the proposed rules would impose substantial costs and significant lead times would be required to upgrade and modify equipment for compliance. Further, such equipment would be subjected to nationally-established conformity assessment procedures administered by BSEE-approved verification organizations. MODUs operate in a global market, and the proposed rules, if implemented, would affect access to U.S. markets by worldwide drilling contractors and equipment manufacturers.

These effects are exacerbated by BSEE's regulatory structure which seemingly limits direct access to BSEE's approval authorities under 30 CFR §§250.141 and 250.142 to "a lessee, the owner or holder of operating rights, a designated operator or agent of the lessee(s), a pipeline right-of-way holder, or a State lessee granted a right-of-use and easement." As noted above, neither an equipment manufacturer nor an equipment owner has access to a binding decision from BSEE regarding the acceptability of equipment as fulfilling regulatory requirements for the U.S. market.

IADC believes that the TBT Notification Procedures for Draft Technical Regulations and Conformity Assessment Procedures should have been followed for this rulemaking proposal.

Inconsistencies regarding "rig" terminology

Various provisions of the existing and proposed rule have the potential to create confusion due to inconsistent use of terminology. For example (not inclusive):

- The proposed §250.712, and the associated Rig Movement Notification Report, refer to "barge", "coiled tubing unit", "drill ship", "jackup", "snubbing unit", "semisubmersible", "submersible", "wire-line unit", "rig", "rig unit", "MODU", "platform rig", and "drilling rig." The use of terminology between the proposed regulation and the associated report does not appear entirely consistent.
- The proposed §250.713 refers to "MODU" and "lift boat", "dynamically positioned rig unit", "moored rigs", and "dynamically positioned MODU." Does a dynamically positioned rig unit differ from a dynamically positioned MODU?
- The proposed §250.715 refers to "MODUs and jack-ups", "jack-up and moored MODUs", "moored MODU or jack-up", and "Rig/facility/platform." The caption for this section implies that a jack-up is not a MODU.
- The proposed §250.723 refers to "rig unit", and "lift boat" and "MODU."

Individually, these differences seem inconsequential; however, they may lead to situations where the exclusion of a term (*e.g.*, lift boat) may lead to the conclusion that the regulation is not intended to apply to operations conducted from lift boats, or that jack-ups are not considered MODUs. IADC suggests that the use of such terminology throughout part 250 be carefully reviewed and consideration be given to adding appropriate definitions where distinctions are necessary, *e.g.* between a lift boat and a self-elevating mobile offshore drilling unit (jack-up).

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Uncertainties regarding responsibilities and liabilities in relation to the BSEE's reinterpretation of the provisions of 30 CFR 250.156(c) and promulgation of Interim Policy Document No. 12-07

Finally, and without prejudice to any pending litigation on the issue, IADC would express, once again, concerns about uncertainties regarding contractor and individual responsibilities and liabilities (as persons performing regulated activities) in relation to the agency's reinterpretation of the provisions of 30 CFR 250.146(c) with respect to joint and several responsibilities, and the promulgation and implementation of Interim Policy Document No. 12-07.

Specifically with regard to the provisions of this proposed rule, such concerns and uncertainties include, but are not limited to:

- Proposed §250.107(a)(4), compliance with lease, plan, and permit terms and conditions. Holding contractors and individuals jointly and severally responsible for compliance with all lease, plan, and permit terms and conditions creates an implicit requirement for contractors or individuals to ascertain all lease, plan, and permit terms and conditions. Is this intended?
- Proposed §250.107(e), orders to shut-in operations. Will such orders be issued to both the "lessee, the owner or holder of operating rights, a designated operator or agent of the lessee(s)" and person actually performing the activity?
- Proposed §250.428(d), reports to the District Manager of immediate actions to ensure the safety of the crew or to prevent a well-control event. Does this create an obligation for contractors to provide individual reports or verify such reports have been submitted by the operator?
- Proposed §250.465(b)(3), End of Operations Reports. Is there any expectation by BSEE that a drilling contractor would bear any obligation for submission of this report?
- Proposed §250.703(c), rig floor surveillance. Who is ultimately responsible for the determination that a well has been secured?
- Proposed §250.712, reports of rig movements. Is it BSEE's expectation that any of these reports will be made directly by a drilling contractor or that the drilling contractor will be held responsible for the report in the absence of any action by the operator?
- Proposed §250.715(f), provision of access to rig location data. Is it BSEE's expectation that such access will be provided directly by a drilling contractor or that the drilling contractor will be held responsible for providing such access in the absence of any action by the operator?
- Proposed §250.720, securing of wells. Does a contractor bear a residual responsibility/liability under this proposed requirement for downhole integrity of the well or the effectiveness of the well plugs?
- Proposed §250.724, real time monitoring. Is there an implicit requirement for contractors or individuals to: (1) maintain duplicate records, and (2) ascertain if the required real-time data gathering, monitoring, recordkeeping and transmission are being undertaken by the operator and to suspend operations if they have not?
- Proposed §250.730(c), follow-up on equipment failure. As it is a provision of API 53, IADC would presume that a prudent drilling contractor would conduct such follow-up; however,

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this differs distinctly from a regulatory obligation to do so. Is it BSEE's expectation that a drilling contractor will be held responsible for the notification in the absence of any action by the operator? What, if any, regulatory obligations are created for equipment manufacturers?

- Proposed §§250.740, 250.741, and 250.746, records and record retention. While IADC would presume that a prudent drilling contractor would maintain relevant records, this too differs distinctly from a regulatory obligation to do so. Is it BSEE's intention that these provisions create a regulatory requirement for contractors or individuals to maintain records duplicating those to be maintained by the operator?

IADC understands the requirements imposed upon BSEE for the use of "plain language" in its regulations and the resulting adoption of the term "you" for placement of regulatory responsibility. However, IADC believes that the need for clarity in the placement of regulatory responsibility must be given priority over ill-considered drafting of "plain language" regulations, particularly in consideration of BSEE's reinterpretation of the provisions of 30 CFR 250.156(c) and the promulgation and implementation of Interim Policy Document No. 12-07.

If you have questions about any portion of this correspondence, or comments provided in the Joint Industry response relating to drilling equipment or operations, please contact me by phone at (713) 292-1964.

Sincerely,



Alan Spackman
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Statement for the Record: International Association of Drilling Contractors

Senate Energy and Natural Resources Committee

Hearing Title:

“Hearing to receive testimony on the Well Control Rule and other regulations related to offshore oil and gas production”

Thank you for the opportunity to submit written comments for the record. The International Association of Drilling Contractors (IADC) is a trade association representing worldwide interests of the onshore and offshore drilling industry since 1940. With over 1,800 members, IADC membership reaches nearly every state in the United States. Our members operate the vast majority of onshore rigs in the United States and offshore, our drilling contractor members operate all the Mobile Offshore Drilling Units (MODUs) operated in areas subject to the jurisdiction of the United States. These comments are offered without prejudice to communications that may be offered directly by IADC member companies.

As a trade association, IADC’s purpose is to advance drilling and completion technology, improve industry health, safety, environmental and training practices; and champion sensible regulation and legislation that facilitate safe and efficient drilling. Through its 17 Committees and 15 global Chapters, IADC creates the space for its members to connect, collaborate and create solutions aimed at addressing the industry’s most critical issues.

Macondo was a tragic accident that took the lives of 11 men. Since then, an unprecedented level of collaboration to research and understand the failures that contributed to the incident has resulted in new technologies, operating systems and programs that address both equipment and safety. In addition to industry reforms, the Department of Interior, through the Bureau of Safety and Environmental Enforcement (BSEE) has proposed and implemented new regulations for offshore operations, which include, but are not limited to, the most recent Well Control Rule. IADC joined the American Petroleum Institute (API) and other trade associations

in providing comments to Interior on the BSEE Well Control Rule. In addition, IADC provided its own comments which are attached to these hearing comments, for the record.

I. Harmful Regulations Impede Economic Growth and Threaten Survivability for the Drilling Contractor

IADC will never object to regulations that are necessary or that enhance safety and operational integrity. And, as in any business, drilling contractors require confidence in and consistency of new regulations, with sufficient lead time to fully implement them.

Throughout IADC, our members share the belief that, for the prevention of blowouts, explosions and fires, well control is critical. IADC and its member experts from across all areas of the industry are working together, ahead of governments everywhere, on the improvement of competency programs and technical solutions that address well control performance.

A powerful example of these collaborative efforts is the recent creation of the Well Control Institute (WCI). WCI is a unique industry oversight body comprising the most senior representatives from operators, drilling contractors and equipment manufacturers. WCI is committed to developing solutions to issues such as blowout preventer equipment reliability and rig crew competency.

Within the context of well control, IADC recently launched WellSharp™, a root and branch overhaul initiated by industry to redefine how well control training and assessment is delivered, with the goal of keeping wells in a safe state throughout their life span to avoid blowouts. IADC accredits training institutions, whether commercial or company in-house, to conduct training that meets or exceeds the curriculum requirements set forth in WellSharp. This new standard requires trainees to be more engaged in the learning process and to undergo individual skills assessments appropriate to their specific well control roles and responsibilities. The knowledge-assessment database identifies specific knowledge gaps and allows instructors to review and close these gaps with each trainee before the completion of training. The system provides metrics regarding alignment between the course taken and the trainee's job position and

also affords analysis of instructor performance. It is a truly unique, multifaceted program developed to accomplish a step-change in well control competency by enhancing crew capabilities and eliminating errors.

A current joint industry effort is the blowout preventer (BOP) reliability and performance improvement program. IADC and the International Association of Oil and Gas Producers are collaborating to develop significant and continuous enhancements to BOP operability and reliability. This is an unprecedented collaboration between drilling contractors, oil and gas producers and equipment manufacturers that began in the U.S. Gulf. It will give far greater assurance that BOPs across the world will function on demand while also driving out costs related to equipment being out of service.

U.S.-based offshore drilling contractors first initiated the data sharing project that underpins the BOP reliability program, based on recommendations for reporting of equipment malfunctions and failure found in API Standard 53, Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition (API 53). The BOP reliability program establishes a permanent performance improvement tool that will track and capture performance of BOP equipment.

As stated via API's written and oral testimony, the Macondo incident provoked assemblage of the largest ever collaboration of well control subject matter experts and principals to create solutions to, and apply continuous improvement in, well control performance. A major focus of these efforts has been the API standards program and other international standardization platforms. IADC has connected its members to work collaboratively as subject matter experts on a vast number of standards committees.

Industry has taken its own initiative to fulfill the responsibility to secure safer, cleaner and more efficient drilling operations. IADC strives to support and work with government agencies to develop regulations that are targeted, relevant and proportionate. Regrettably, recent U.S. offshore regulatory initiatives could actually lead to a less safe drilling environment.

IADC believes the newly proposed regulation on well control and blowout prevention by BSEE is precisely the type of overly prescriptive regulation that restrains best industry safety practice and its subsequent benefits: innovation, jobs and economic growth.

IADC readily acknowledges and commends efforts of BSEE staff to produce such a major draft rule. We also appreciate the tremendous external pressures applied to the Bureau by opponents to the U.S. oil and gas industry, many of whom are uninformed and inexperienced in the matters of well control and offshore operational integrity. However, the (undoubtedly) unintended consequences of BSEE's inflexibly prescriptive well control rule fails to account for and encourage substantial industry improvements post-Macondo. In some cases, the requirements of the rule are simply unfeasible, requiring industry to operate sub-optimally. In addition, measures in the rule differ widely from international standards and will negatively impact the market for U.S. MODUs.

IADC's formal response to the BSEE draft BOP rule, minus its detailed technical annexes, is attached to this statement for the Committee's convenience. The Committee should note that IADC, along with other key organizations and associations, has urged BSEE to continue to work with industry to jointly analyze "respective sections of the proposed rule in order to reach mutual understanding of the proposal, to correct fundamental flaws in the proposed rule, and allow constructive development of rules that are ultimately both workable and effective. We further request that the comment period be reopened during the workshops and that the presentation and discussion be part of the official record."¹ We sincerely hope the Bureau will respond to the unanimous call from industry experts and leaders in this respect.

II. Arctic Drilling

Offshore drilling in the Arctic can be done safely without loss to life or peril to the environment. Arctic drilling is already occurring not just in the U.S., but in Canada, Greenland

¹ Industry's joint comments submitted to the Department of Interior in response to BSEE's proposed rulemaking entitled, "Oil and Gas and Sulphur Operations in the Outer Continental Shelf – Blowout Preventer Systems and Well Control". Comments were submitted via electronic submission to: <http://www.regulations.gov/>

and Norway where, for decades, they have demonstrated that drilling safely in the Arctic is possible.

IADC has established, through its Operational Risk Management Task Force and its work on Human Factors (HF),² a risk-based approach to operations planning and control. Integration of risk control methodologies and enhanced well control training, combined with the IADC HSE Case Guidelines for Mobile Offshore Drilling Units, and other programs, makes it entirely possible to plan and execute Arctic wells that protect safety and the environment. Norway, a chief example, has a long tradition of safe, efficient and environmentally sensitive operations in hostile seas above the Arctic Circle.

Closing

Overall, the next three years will be challenging for drilling contractors due to uncertainty over oil prices and federal regulations. History shows that, with the ebb and flow of the oil market, industry should expect continued decline in U.S. crude oil production before it resumes growth again in late 2016, as EIA estimates.³ It remains to be seen how industry will fare in the upswing as a result of impacts of potentially deleterious regulation, such as those that are currently proposed. The U.S. industry has, by its own innovation and advanced technology, secured both an energy price miracle for Americans, and the world's top spot in oil production. The question U.S. policy makers must decide is whether their ambition is for the U.S. to responsibly develop these resources and continue setting an outstanding world example, or bequeath that to another jurisdiction.



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Att. IADC letter to BSEE

² HF is the scientific discipline applying to the interaction between humans and the working environment and systems.

³ <http://www.eia.gov/forecasts/steo/report>