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BSEE
Attention: Regulations and Standards Branch
45600 Woodland Road
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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 provides its 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.

1. Overview

API's comments set forth in this letter describe approaches that we 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

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.”)

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 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, API offers recommendations to best assure that this “acceptable balance” can take shape.

3. API Urges 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

² National Petroleum Council. *Arctic Potential: Realizing the Promise of U.S. Arctic Oil and Gas Resources*. 2015.

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. API Urges Withdrawal of the Proposed Requirement that Operators Submit an Integrated Operations Plan (IOP)

API requests 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 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.

API also objects 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, API urges 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]hough 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.” API requests 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.

API urges that the IOP requirement should be withdrawn.

5. API Urges Adoption of Regulations That Accept Alternative Approaches to Response to Loss of Well Control

API recognizes 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, API urges 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, API urges 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. API Urges 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, API urges 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, “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 API and its 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

³ Izon, 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.

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, API believes 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. API Urges 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

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.

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. API is 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 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

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. API Urges 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

⁵ Neff, J. "Fate and Effects of Water Based Drilling Muds and Cuttings in Cold Water Environments". Duxbury MA, May 2010.

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. API Urges 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, API urges 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. API Urges 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, API believes 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, API objects 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.

API strongly encourages 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. API also supports 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. API Urges 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. API requests 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, API requests 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. API Urges 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, 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.

Thank you for considering these comments. If you have any questions, please do not hesitate to contact the undersigned.

Very truly yours,

A handwritten signature in black ink that reads "Richard Ranger". The signature is written in a cursive, flowing style.

Richard Ranger
Senior Policy Advisor
American Petroleum Institute

cc: Secretary of Interior Sally Jewell
Director Abigail Ross Harper, Bureau of Ocean Energy Management
Director Brian Salerno, Bureau of Safety and Environmental Enforcement