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DEPARTMENT OF THE INTERIOR

Bureau of Safety and Environmental Enforcement

30 CFR Part 250

Bureau of Ocean Energy Management

30 CFR Part 550

[Docket ID: BSEE–2019–0008, EEEE500000, 21XE1700DX, EX1SF0000.EAQ000]

RIN 1082–AA01

Oil and Gas and Sulfur Operations on the Outer Continental Shelf—Revisions to the Requirements for Exploratory Drilling on the Arctic Outer Continental Shelf

AGENCIES: Bureau of Safety and Environmental Enforcement (BSEE); Bureau of Ocean Energy Management (BOEM), Interior.

ACTION: Proposed rule.

SUMMARY: The Department of the Interior (DOI or Department), acting through BOEM and BSEE, has reviewed and is proposing to revise its existing regulations for exploratory drilling and related operations on the Arctic Outer Continental Shelf (OCS), to reduce unnecessary burdens on stakeholders while ensuring that energy exploration on the Arctic OCS is safe and environmentally responsible. In particular, this proposed rule would revise certain requirements promulgated through the rule entitled, *Oil and Gas and Sulfur Operations on the Outer Continental Shelf-Requirements for Exploratory Drilling on the Arctic Outer Continental Shelf* (''2016 Arctic Exploratory Drilling Rule''). This proposed rule would also add new provisions to BSEE's regulations pertaining to suspensions of operations (SOO), and BOEM's Exploration Plan (EP) and Development and Production Plan (DPP) regulations.

DATES: Submit comments by February 8, 2021. BSEE and BOEM may not fully consider comments received after this date. You may submit comments to the Office of Management and Budget (OMB) on the information collection burden in this proposed rule by January 8, 2021. The deadline for comments on the information collection burden does not affect the deadline for the public to comment to BSEE and BOEM on the proposed regulations.

ADDRESSES: You may submit comments on BSEE's or BOEM's sections of the rulemaking by any of the following methods. For comments on this proposed rule, please use the Regulation Identifier Number (RIN) 1082–AA01 as an identifier in your message. For comments specifically related to the draft Environmental Assessment (EA) conducted under the National Environmental Policy Act of 1969 (NEPA), please refer to NEPA in the heading of your message. See also Public Availability of Comments under Procedural Matters.

- *Federal eRulemaking Portal: http://www.regulations.gov.* In the entry entitled, ''Enter Keyword or ID,'' enter BSEE–2019–0008, then click search. Follow the instructions to submit public comments and view supporting and related materials available for this rulemaking. BSEE and BOEM may post all submitted comments.
- *Mail or hand-carry comments to the DOI, BSEE and BOEM:* Attention: Regulations and Standards Branch, 45600 Woodland Road, VAE–ORP, Sterling VA 20166. Please reference RIN 1082–AA01, ''Oil and Gas and Sulfur Operations on the Outer Continental Shelf—Revisions to the Requirements for Exploratory Drilling on the Arctic Outer Continental Shelf,'' in your comments, and include your name and return address.
- Send comments on the information collection in this rule to: Interior Desk Officer 1082–AA01, Office of Management and Budget; 202–395–5806 (fax); or via the online portal at *RegInfo.gov*. Please also send a copy to BSEE and BOEM by one of the means previously described.
- Public Availability of Comments—Before including your address, phone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. For BSEE and BOEM to withhold from disclosure your personal identifying information, you must identify any information contained in the submittal of your comments that, if released, would constitute a clearly unwarranted invasion of your personal privacy. You must also briefly describe any possible harmful consequence(s) of the disclosure of information, such as embarrassment, injury, or other harm. While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

FOR FURTHER INFORMATION CONTACT: For technical questions related to regulatory changes BSEE is proposing in Part 250, contact Mark E. Fesmire, BSEE, Alaska Regional Office, *mark.fesmire@bsee.gov,* (907) 334–5300. For technical questions related to regulatory changes BOEM is proposing in Part 550, contact Joel Immaraj, BOEM, Alaska Regional Office, *joel.immaraj@boem.gov,* (907) 334–5238. For procedural questions contact Bryce Barlan, BSEE, Regulations and Standards Branch, *regs@bsee.gov,* (703) 787–1126.

SUPPLEMENTARY INFORMATION:

Executive Summary

In response to BSEE- and BOEM-initiated environmental and safety reviews of potential oil and gas operations on the Arctic OCS, experiences gained from Shell's 2012 and 2015 Arctic operations, and concerns expressed by environmental organizations and Alaska Natives, BSEE and BOEM published the 2016 Arctic Exploratory Drilling Rule (*see* 81 FR 46478, July 15, 2016). The rule was narrowly focused, applying solely to exploratory drilling operations conducted during the Arctic OCS open-water drilling season by drilling vessels and ''jack-up rigs'' (collectively known as mobile offshore drilling units or MODU) in the Beaufort Sea and Chukchi Sea Planning Areas. The regulations were intended to ensure that Arctic OCS exploratory drilling operations are conducted in a safe and responsible manner, while taking into account the unique conditions of the Arctic OCS, as well as Alaska Natives' cultural traditions and their need for access to subsistence resources. BSEE and BOEM have since reviewed the 2016 Arctic Exploratory Drilling Rule taking into account a Congressional declaration of purposes in the Outer Continental Shelf Lands Act (OCSLA) to ''establish policies and procedures for managing the oil and natural gas resources of the Outer Continental Shelf which are intended to result in expedited exploration and development of the Outer Continental Shelf in order to achieve national economic and energy policy goals, assure national security, reduce dependence on foreign sources, and maintain a favorable balance of payments in world trade.'' [1] The bureaus have also reviewed new information about technological developments in an ice environment. Based on that review, BSEE and BOEM are proposing revisions in this proposed rule that are consistent with OCSLA, and would reduce unnecessary burdens on stakeholders while still maintaining safety and environmental protection.

Since publication of the 2016 Arctic Exploratory Drilling Rule, new

[1] Outer Continental Shelf Lands Act, Public Law 95–372, sec. 102 (Sept. 8, 1978), 43 U.S.C. 1802(1)).

Executive Orders (E.O.) and Secretary's Orders (S.O.) called on Federal agencies to review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately begin processes to potentially suspend, revise, or rescind those regulations that are determined to unduly burden the development of domestic energy resources, beyond the degree necessary to protect the public interest or otherwise comply with the law. Executive Order 13795, *Implementing an America-First Offshore Energy Strategy* (82 FR 20815) and Secretary's Order 3350, *America-First Offshore Energy Strategy,* which are discussed in more detail below in *Section I. Background, Subsection C. Executive and Secretary's Orders,* specifically called for a review of the 2016 Arctic Exploratory Drilling Rule.[2] In response to these E.O.s and S.O.s, BSEE and BOEM undertook a review of the regulations promulgated through the 2016 Arctic Exploratory Drilling Rule with a view toward encouraging energy exploration and production on the Arctic OCS, as appropriate and consistent with applicable law, and reducing unnecessary regulatory burdens, while ensuring that any such activity is safe and environmentally responsible.

BSEE's and BOEM's views about certain features of the existing regulations were also informed by new information that has become available since the 2016 rule was finalized. This new information includes a BSEE-commissioned Technology Assessment Program (TAP) study entitled, *Suitability of Source Control and Containment Equipment versus Same Season Relief Well in the Alaska Outer Continental Shelf Region* (Bratslavsky and SolstenXP, 2018) and a National Petroleum Council (NPC) report entitled, *Supplemental Assessment to the 2015 Report on Arctic Potential: Realizing the Promise of U.S. Arctic Oil and Gas Resources* (NPC 2019 Report). BSEE also re-assessed the original NPC report entitled, *Arctic Potential: Realizing the Promise of U.S. Arctic Oil and Gas Resources* (NPC 2015 Report; together with the NPC 2019 Report, the NPC reports). Both NPC reports include discussions about global Arctic operations. These global operations are discussed in further detail below in *Subsection 5. Industry Interest in the Arctic OCS* of *Section I. Background,* under the subheading entitled, *Global Arctic Exploration Activities.* The Bratslavsky and SolstenXP study was finalized in October 2018 and may be downloaded from BSEE's TAP website at: *https://www.bsee.gov/research-record/suitability-of-source-control-containment-equipment-versus-same-season-relief-well.* The NPC 2019 Report was finalized in April 2019 and may be downloaded from an NPC website at: *https://www.npc.org/ARSA-FINAL-052219-LoRes.pdf.* The NPC 2015 Report was finalized in March 2015 and may be downloaded from an NPC website at: *http://www.npcarcticpotentialreport.org/index.html.*

Based on the results of these reports, BSEE and BOEM are proposing to amend, revise, or remove certain current regulatory provisions promulgated through the 2016 Arctic Exploratory Drilling Rule, to reduce unnecessary burdens on stakeholders while still maintaining safety and environmental protection. This proposed rulemaking is consistent with OCSLA's Congressional declaration of purposes to ''establish policies and procedures for managing the oil and natural gas resources of the Outer Continental Shelf which are intended to result in expedited exploration and development of the Outer Continental Shelf in order to achieve national economic and energy policy goals, assure national security, reduce dependence on foreign sources, and maintain a favorable balance of payments in world trade.'' 43 U.S.C. 1802(1).

BSEE and BOEM also considered another issue on the Arctic OCS in addition to those addressed in the 2016 Arctic Exploratory Drilling Rule, but is logical to address as part of this rulemaking to further encourage safe and environmentally responsible exploration of this region, where the areas known to have oil and gas have been explored or studied. This issue pertains to the effective means by which BSEE and the operator could address seasonal weather-related constraints in the Arctic OCS that severely impact the operator's ability to safely perform leaseholding operations for a significant portion of the term on a lease.

Accordingly, this proposed rule would revise certain provisions in 30 Code of Federal Regulations (CFR) Part 250, Subparts A, C, D, and G, and 30 CFR part 550, subpart B, that pertain to:

1. The factors that the BSEE Regional Supervisor may evaluate in assessing whether to grant an SOO, to address unique and specific conditions relevant only to exploration and development activities on the Arctic OCS;
2. Pollution prevention;
3. Arctic OCS Source Control and Containment Equipment (SCCE);
4. Relief rig capabilities for the Arctic OCS;
5. Timing and submission requirements related to Integrated Operations Plans (IOP) for proposed Arctic exploratory drilling;
6. What must be included in the IOP; and
7. What data and information must accompany the EP and DPP.

This proposed rule is designed to reflect the need to ensure the safe, effective, and responsible exploration of Arctic OCS oil and gas resources, while protecting the marine, coastal, and human environments, and preserving Alaska Natives' cultural traditions and their access to subsistence resources. This proposed rule is intended to revise the regulations promulgated through the 2016 Arctic Exploratory Drilling Rule by creating more flexible and less costly compliance options in BSEE's and BOEM's regulations that could achieve these objectives. While this proposed rule seeks to promulgate new provisions in addition to those addressed in the 2016 Arctic Exploratory Drilling Rule, these new provisions (*i.e.,* provisions to address leaseholding operations impacted by seasonal weather-related constraints on the Arctic OCS) would further enhance BSEE's and BOEM's abilities to ensure the safe, effective, and responsible exploration of Arctic OCS oil and gas resources. They would do so while protecting the marine, coastal, and human environments, and preserving Alaska Natives' cultural traditions and access to subsistence resources. Through lease stipulations related to the Conflict Avoidance Agreements (CAA), BOEM currently requires operators to consult with affected subsistence communities and describe in exploration and development plans the mitigating practices the operator would undertake to avoid conflicts with the communities. Conflict Avoidance Agreements provide a framework for mitigating the adverse impacts a drilling project may have on subsistence activities, values, and uses.

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[2] These Orders did no dictate outcomes; rather, they directed a review in accordance with applicable law.

LIST OF ACRONYMS AND REFERENCES

60-Day report	Report to the Secretary of the Interior, review of Shell's 2012 Alaska Offshore Oil and Gas Exploration Program
2016 Arctic Exploratory Drilling Rule	Oil and Gas and Sulfur Operations on the Outer Continental Shelf-Requirements for Exploratory Drilling on the Arctic Outer Continental Shelf, 81 FR 46478, July 15, 2016 (available at *https://www.doi.gov/sites/doi.gov/files/migrated/news/pressreleases/upload/Shell-report-3-8-13-Final.pdf.*).
ABS	American Bureau of Shipping.
ACP	Alternative Compliance Program.
ADNR	Alaska Department of Natural Resources.
AEWC	Alaska Eskimo Whaling Commission.
ANILCA	Alaska National Interest Lands Conservation Act.
ANCSA	Alaska Native Claims Settlement Act.
ANWR	Arctic National Wildlife Refuge.
APD	Application for Permit to Drill.
API	American Petroleum Institute.
Arctic OCS	OCS within the Beaufort Sea and Chukchi Sea Planning Areas.
AWKS	Alternative Well Kill System.
BOEM	Bureau of Ocean Energy Management.
BOEMRE	Bureau of Ocean Energy Management, Regulation and Enforcement.
BOP	Blowout Preventer.
Bratslavsky and SolstenXP, 2018	Suitability of Source Control and Containment Equipment versus Same Season Relief Well in the Alaska Outer Continental Shelf Region, October 2018.
BSEE	Bureau of Safety and Environmental Enforcement.
BLM	Bureau of Land Management.
CAA	Conflict Avoidance Agreement.
CFR	Code of Federal Regulations.
CZMA	Coastal Zone Management Act.
CWA	Clean Water Act.
Department	Department of the Interior.
DNV GL	Det Norske Veritas and Germanischer Lloyd.
DOCD	Development Operations Coordination Document.
DOI	Department of the Interior.
DPP	Development and Production Plan.
EA	Environmental Assessment.
EIA	Environmental Impact Analysis.
EIS	Environmental Impact Statement.
E.O.	Executive Order.
EP	Exploration Plan.
EPA	Environmental Protection Agency.
ESA	Endangered Species Act.
G&G	Geological and geophysical.
IC	Information Collection.
ICAS	Inupiat Community of the Arctic Slope.
IOP	Integrated Operations Plan.
IRIA	Initial Regulatory Impact Analysis.
IWC	International Whaling Commission.
LMRP	Lower Marine Riser Package.
MASP	Maximum Anticipated Surface Pressures.
MMPA	Marine Mammal Protection Act.
MMS	Minerals Management Service.
MODU	Mobile Offshore Drilling Unit.

LIST OF ACRONYMS AND REFERENCES—Continued

60-Day report	Report to the Secretary of the Interior, review of Shell's 2012 Alaska Offshore Oil and Gas Exploration Program
NAICS	North American Industry Classification System.
NEPA	National Environmental Policy Act of 1969.
NMFS	National Marine Fisheries Service.
NOAA	National Oceanic and Atmospheric Administration.
NPC	National Petroleum Council.
NPC 2015 Report	Arctic Potential: Realizing the Promise of U.S. Arctic Oil and Gas Resources.
NPC 2019 Report	Supplemental Assessment to the 2015 Report on Arctic Potential: Realizing the Promise of U.S. Arctic Oil and Gas Resources.
NPDES	National Pollutant Discharge Elimination System.
NPR–A	National Petroleum Reserve—Alaska.
NSB	North Slope Borough.
NTL	Notice to Lessees and Operators.
OCS	Outer Continental Shelf.
OCSLA	Outer Continental Shelf Lands Act.
ODCE	Ocean Discharge Criteria Evaluations.
OIRA	Office of Information and Regulatory Affairs.
OMB	Office of Management and Budget.
ONRR	Office of Natural Resources Revenue.
OSRP	Oil Spill Response Plan.
PFD	Permanent Fund Dividend.
PRA	Paperwork Reduction Act.
psi/ft	pounds per square inch per foot.
RIN	Regulation Identifier Number.
ROV	Remotely Operated Vehicle.
RP	Recommended Practice.
SCCE	Source Control and Containment Equipment.
Secretary	Secretary of the Interior.
S.O.	Secretary's Orders.
SEMS	Safety and Environmental Management Systems.
SSID	Subsea Isolation Device.
SSRW	Same Season Relief Well.
SOO	Suspensions of Operations.
TAP	Technology Assessment Program.
TAPS	Trans-Alaska Pipeline System.
TCF	Trillion Cubic Feet.
UMRA	Unfunded Mandates Reform Act of 1995.
U.S.	United States.
USCG	U.S. Coast Guard.
USFWS	U.S. Fish and Wildlife Service.
USGS	United States Geological Survey.
Utquiavik	Barrow.
WCD	Worst Case Discharge.

I. Background

A. Overview of the Alaska Arctic Region

1. History of Arctic Oil and Gas Development

Although Alaska's first oil production is attributable to the 1957 Swanson River discovery on the Kenai Peninsula, oil and gas resources have been known to exist in the Arctic since as early as 1839. Early explorers had reported that Alaska Natives on the Arctic coast used oil-soaked tundra for fuel. The oil came from natural oil seeps on the ground. However, the extent of the resource, as well as the State's overall oil and gas endowment, would not be realized until the discovery of the Arctic's Prudhoe Bay oil field on the North Slope and completion of the Trans-Alaska Pipeline System (TAPS) in 1977.

The Prudhoe Bay field was discovered on March 12, 1968, with the drilling of the Prudhoe Bay State #1 well. BP Exploration drilled a confirmation well the following year. However, production did not come online until June 20, 1977, after the TAPS was completed and other companies with lease holdings in the area undertook a host of activities to delineate the reservoir, resolve equity participation, and put together initial infrastructure for the field. After over 40 years of production, Prudhoe Bay remains the largest oil field in North America and is the 18th largest field ever discovered worldwide.[3] According to data maintained by the Alaska Oil and Gas Conservation Commission, Alaska's North Slope has produced over 17.3 billion barrels of oil, with Prudhoe Bay contributing approximately 68 percent of that amount.[4] Currently, the only offshore Federal production in the Arctic OCS[5] is Hilcorp's Northstar field, which includes both State and Federal acreage in the 8(g) Zone.[6] Located in the Beaufort Sea about 12 miles northwest of Prudhoe Bay, this prospect has been producing since 2001. Over 150 million barrels of oil have been produced to date at Northstar. In 2019, the Federal Government received nearly $5 million in royalty payments from oil production on Federal leases at Northstar, and from 2003 to 2018, royalty payments ranged

[3] *https://dec.alaska.gov/spar/ppr/response/sum_fy06/060302301/factsheets/060302301_factsheet_PB.pdf.*

[4] *http://aogweb.state.ak.us/DataMiner3/Forms/Production.aspx.*

[5] There are Federal OCS leases that do not have ongoing production in the Cook Inlet, which is not considered part of the Arctic.

[6] Section 8(g) of the OCSLA requires the Federal Government to share with the State of Alaska 27% of revenue from leases in the 8(g) Zone (the first three nautical miles of the Outer Continental Shelf). 43 U.S.C. 1337(g).

from $3 million to over $20 million in any given year. In 2019, the Federal Government disbursed just over $1.5 million to the State of Alaska for Northstar Federal leases in the 8(g) Zone.[7]

The construction of TAPS enhanced the significance of the Arctic's production to the State of Alaska. TAPS is an 800-mile-long pipeline system that was designed to accommodate the transport of over 2 million barrels of oil per day. The pipeline begins at Prudhoe Bay and stretches south to Valdez in southern Alaska, which is the northernmost ice-free port in North America. TAPS is one of the world's largest pipeline systems, an engineering icon that was the biggest privately funded construction project when it was constructed in the 1970s. At peak flow in 1988, 11 pump stations helped to move 2.1 million barrels of oil a day.[8]

2. Budgetary Economic Impact on the People of Alaska

North Slope Alaska oil and gas exploration and production has been a significant economic driver, not only to the State of Alaska and Alaskan Native communities, but also to the national domestic energy supply. The State's oil and gas endowments have provided greater economic prosperity to its people than other important resources in the State. Specifically, Alaska relies on revenues generated from oil and gas resources, along with other revenue-generating streams, to fund a major portion of the State's operating and capital budgets. This has allowed Alaska to be the only State in the United States that does not have either a State sales tax or personal income tax. Oil and gas revenues are generated by means of a variety of taxes, royalties, and other charges related to oil and gas development and production. Other examples of revenue-generating streams for Alaska include corporate income, fuel, alcohol, and tobacco taxes. In 2016, 72 percent of Alaska's unrestricted general funds, which come from the State's overall revenue-generating stream, were derived from oil and gas revenues and were available to the State's budget.[9] In 2012, as much as 93 percent of Alaska's unrestricted general funds were derived from oil and gas revenues and were also available to the State's budget.[10] The reduced contribution of oil and gas-generated revenue to the State's budget since 2012 is due primarily to declining oil production in the North Slope, but also due to a general downward trend in oil prices.

Aside from annual State operating and capital budgets, several Statewide government programs established for the benefit of the people of Alaska are largely dependent on oil and gas-related revenues, most notably the Alaska Permanent Fund. In 1976, Alaska's State constitution was amended to establish the Alaska Permanent Fund, which provides that at least 25 percent of all mineral lease rentals, royalties, royalty sale proceeds, Federal mineral revenue sharing payments, and bonuses received by the State are to be placed in a permanent fund, known as the Alaska Permanent Fund, the principal of which is used only for income-producing investments. All income generated from the permanent fund is available for distribution to all Alaskan residents—adults and children—on an annual basis through the State's Permanent Fund Dividend (PFD) program.[11] Since 1978, this fund has grown to a total fund value of $60 billion as of March 2020.[12] Individual distributions to Alaskans from the fund have ranged from $386 per person to as high as $2,072 per person.[13] These annual payments are estimated to have lifted between 15,000 and 25,000 Alaskans above the Federal poverty line.[14]

Much of the North Slope Borough's economy is tied to the oil and gas industry, primarily in the greater Prudhoe Bay region. Some borough residents have rotational work in the oilfields or in a position supporting the oil industry, but the greatest contribution to the economy is through tax revenue. The borough assesses property taxes on infrastructure, the primary funding source for the borough's operations and capital projects, which include building roads, operating schools, and funding for other public services, such as health clinics and fire departments.[15]

In March and April of 2020, global oil prices experienced significant volatility due to a confluence of events, including decreased demand from coronavirus effects, as well as production output negotiations between OPEC and Russia. These events caused the price of oil to slide to 17-year lows. While prices have already partially recovered and stabilized, this could affect interest and activity in the region if the low-price environment continues into the future, as drilling and other exploration activities in the Arctic are more expensive than other regions. Given the long period of time before exploratory drilling in the Arctic is expected to start and the short-term nature of the underlying price events, the Bureaus expect that prices will continue to rebound. The events in 2020 also underscore the importance of ensuring that BOEM and BSEE regulations are no more burdensome than necessary to protect safety and the environment.

3. Arctic Resource Potential and Geology

The Arctic region is characterized by its extensive oil and gas resources. The Arctic Alaska Petroleum Province, which consists of up to 43 geologic plays between the Chukchi Sea and the Beaufort Sea planning areas, extends about 684 miles from the United States-Canadian border westward to the maritime boundary with Russia, and from 62 to 372 miles northward from the Brooks Range to the approximate edge of the Continental Shelf. Although the edge of the Continental Shelf provides a well-defined physiographic boundary for the province, this edge does not represent a geologic limit to potential petroleum resources. The offshore part of the province is characterized by a relatively narrow (62-mile-wide) shelf in the Beaufort Sea and a broad (372-mile-wide) shelf in the Chukchi Sea. The province is bounded onshore on the south by the Brooks Range-Herald mountain range and offshore to the north by the passive continental margin of the Canada Basin.[16] In general, the formations are fairly continuous across the Arctic Alaska Petroleum Province.

Although most of the Arctic's oil production to date is attributed to the North Slope, most of the undiscovered resources are located off the Arctic coast, within the Chukchi Sea and Beaufort Sea Planning Areas. According to BOEM's 2016 Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's

[7] *https://revenuedata.doi.gov/downloads/disbursements/.*

[8] *https://www.alyeska-pipe.com/TAPS.*

[9] *https://www.legfin.akleg.gov/,* Budget History Data (Excel) (posted 1–15–2020), Row 59.

[10] *https://www.legfin.akleg.gov/,* Budget History Data (Excel) (posted 1–15–2020), Row 55.

[11] *https://apfc.org/frequently-asked-questions/#why-did-alaskans-create-the-fund.*

[12] *https://apfc.org/our-performance/.*

[13] *https://pfd.alaska.gov/Division-Info/Summary-of-Applications-and-Payments.*

[14] Berman, Matt., Random Reamy. "Permanent Fund Dividends and Poverty in Alaska." Institute of Social and Economic Research, University of Alaska Anchorage. (November 2016), available online at: *https://iseralaska.org/static/legacy_publication_links/2016_12-PFDandPoverty.pdf.* p. 25 of pdf.

[15] *http://www.north-slope.org/assets/images/uploads/13_Economic_Development_-_NSB_Comprehensive_Plan.pdf.*

[16] Houseknecht, D.W., and Bird, K.J., 2006, Oil and gas resources of the Arctic Alaska petroleum province: U.S. Geological Survey Professional Paper 1732–A, 11 p., available online at: *http://pubs.usgs.gov/pp/pp1732/pp1732a/.*

OCS (mean estimates available at *http://www.boem.gov/National-Assessment-2016/*), there are approximately 23.6 billion barrels of undiscovered technically recoverable oil and about 104.4 trillion cubic feet (TCF) of technically recoverable natural gas (mean estimates) in the combined Beaufort Sea and Chukchi Sea Planning Areas. BOEM re-assessed its Beaufort Sea Planning Area estimates due to recent onshore discoveries in the National Petroleum Reserve-Alaska (NPR–A) from two formations that extended offshore. In December 2017, BOEM published its updated re-assessment (mean estimates available at *https://www.boem.gov/2016a-National-Assessment-Fact-Sheet/*), which estimated that there are approximately 24.3 billion barrels of technically recoverable oil and about 104. TCF of technically recoverable natural gas in the combined Beaufort Sea and Chukchi Sea Planning Areas; an increase of about 680 million barrels of oil and 100 billion cubic feet of natural gas. Of the 24.3 billion barrels of oil, the Chukchi Sea Planning Area makes up about 63% of the estimate, while the Beaufort Sea Planning Area makes up 37%. With respect to gas, the Chukchi Sea Planning Area makes up about 73% of the 104.5 TCF of gas and the Beaufort Sea Planning Area makes up 27% of the estimate. These estimates represent about one-quarter of the technically recoverable oil resources and one-third of the technically recoverable gas resources on the OCS.

While not as large, the Arctic's onshore undiscovered oil and gas resources are also considerable. In January 2020, the United States Geological Survey (USGS) published an assessment of undiscovered oil and gas resources in the central portion of the Alaska North Slope, (mean estimates available at *https://pubs.usgs.gov/fs/2020/3001/fs20203001.pdf*). The assessment estimated that there are approximately 3.6 billion barrels of undiscovered technically recoverable oil and about 8.9 TCF of undiscovered technically recoverable natural gas resources on State and Native lands, and State waters, east of the NPR–A and west of the Arctic National Wildlife Refuge (ANWR). According to a 2017 USGS assessment of undiscovered oil and gas resources in the Alaska North Slope, (mean estimates available at *https://pubs.usgs.gov/fs/2017/3088/fs20173088.pdf*), there are approximately 8.8 billion barrels of undiscovered technically recoverable oil and about 39 TCF of undiscovered technically recoverable natural gas in the NPR–A. In addition, USGS's assessment of the 1002 Area [17] of the ANWR estimated (mean estimates available at *https://pubs.usgs.gov/of/2005/1217/pdf/2005-1217.pdf*) there are 7.6 billion barrels of technically recoverable oil and 7.04 [18] TCF of technically recoverable natural gas. Efforts are already underway to bring some of these new onshore resources online. Collectively, these offshore and onshore assets are enormous, and most of the resources are located offshore.[19] However, the Arctic OCS's vast potential has yet to be realized.

In the Arctic, the circumstances associated with drilling from a MODU can be different than those in the Gulf of Mexico. The geological pressures in the hydrocarbon bearing zones in the shallow seas of Alaska's Arctic are, in many cases, likely to be substantially lower than those encountered during the Deepwater Horizon incident, reducing certain risk factors of a major blowout. As reviewed by the NPC, through the NPC 2019 Report, subsurface conditions (below the seafloor) for the Arctic OCS—geology, pressure, resource depth, and drilling depth—are much simpler as compared to other areas, such as the deepwater Gulf of Mexico OCS. The NPC 2019 Report states that the targeted Arctic potential reservoirs are shallow and normally pressured, but that exploration and development are dominated by other challenges, such as water depth, ice conditions, and the length of the open-water season, which make the Arctic unique (NPC 2019 Report at 10). The NPC 2015 Report found, however, that most of the U.S. Arctic offshore conventional oil and gas potential can be developed using existing field-proven technology, which was reaffirmed by the NPC 2019 Report (NPC 2015 Report at 28).

As identified by the NPC, targeted potential reservoirs in the Arctic OCS may be shallow and normally pressured.[20] However, this condition is not consistent throughout all areas in the Arctic OCS that have already been explored. For example, a study published by the American Rock Mechanics Association [21] analyzed wells drilled in the Chukchi Sea in order to provide an improved interpretation and delineation of pore pressure in the Chukchi shelf region. A majority of the wells contained significant overpressure at depths ranging from 1,098 to 2,317 meters (*i.e.,* 3,602 to 7,601 feet) subsea. In the Beaufort Sea, the Alaska Department of Natural Resources (ADNR) noted that, as part of its findings to support Beaufort Sea areawide oil and gas lease sales,[22] operators may reasonably expect to encounter extremely high pore pressures along the central Beaufort Sea region where ''. . . Cenozoic strata (sedimentary layers) are very thick, such as in the Kaktovik, Camden, and Nuwuk Basins,'' and suggests that challenges from over pressured areas could be reduced by ''. . . identifying locations of overpressured sediments via seismic data analysis, and then adjusting the mud mixture accordingly as the well is drilled.'' In the Point Thomson area, for example, where drilling has taken place from an onshore facility into a reservoir located primarily offshore, the pore pressure gradients were measured as high as 0.8 pounds per square inch per foot (psi/ft) at depths of 2.5 miles (13,200 feet). A pore pressure gradient of 0.433 psi/ft is considered normal in this area.[23]

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[17] The Alaska National Interest Lands Conservation Act (ANILCA) of 1980 required ANWR to be managed as a protected wilderness. Section 1002 of ANILCA, however, deferred a decision regarding future management of a 1.5 million-acre coastal plain portion of ANWR (known as the ''1002'' area) in order to continuously study the various natural resources on the coastal plain, and analyze how oil and gas exploration, development, and production could potentially impact those resources. Section 20001 of the Tax Cuts and Jobs Act of 2017 lifted a provision in Section 1003 of ANILCA that prohibits oil and gas leasing and production in the 1002 area, and the BLM is in the process of developing an oil and gas leasing program for that area.

[18] This value represents the combined estimates of natural gas that could technically be produced from gas fields as well as associated gas that could be produced from oil fields.

[19] D.L. Gautier *et al.,* ''Circum-Arctic Resource Appraisal: Estimates of Undiscovered Oil and Gas North of the Arctic Circle,'' U.S. Geological Survey, USGS Fact Sheet 2008–3049, 2008. M.E. Brownfield *et al.,* ''An Estimate of Undiscovered Conventional Oil and Gas Resources of the World,'' U.S. Geological Survey, USGS Fact Sheet 2012–3024, 2012, available at *https://pubs.usgs.gov/fs/2008/3049/fs2008-3049.pdf.*

[20] ''Normally pressured'' is not defined in the NPC 2019 Report. However, as a general matter, normal pressure generally refers to the hydrostatic pressure within a well. ''Normally pressured'' refers to conditions present when formation pressures are predictable at any given depth and follow a normal formation pressure gradient or ''hydrostatic pressure gradient.'' Normal formation pressure, at any given depth, equals the normal formation pressure gradient multiplied by the depth. The normal pressure is expressed in pounds per square inch (psi).

[21] Elowe, K.E., & Sherwood, K.W., 2017, ''Abnormal Formation Pressure in the Chukchi Shelf, Alaska,'' American Rock Mechanics Association Conference Paper, Document ID ARMA–2017–0194, available online at *https://www.onepetro.org/conference-paper/ARMA-2017-0194.*

[22] Alaska Department of Natural Resources, 2019, ''Beaufort Sea Areawide Oil and Gas Lease Sales,'' p. 3–20, available online at *https://aws.state.ak.us/OnlinePublicNotices/Notices/View.aspx?id=193811.*

[23] Craig, J.D., K.W. Sherwood, and P.P. Johnson. 1985. Geologic report for the Beaufort Sea planning

Continued

While these reports' findings do not fully align with the NPC's findings, there are other sources of information confirming that, to a certain degree, typical geologic conditions in the Arctic OCS are normally pressured. For example, a BOEM report that studied the Chukchi Sea's Burger gas discovery calculated the pore pressure gradient for one of the Chukchi Sea wells in the study to be 0.44 psi/ft up to 4,850 feet subsea, which the report determined to be normally pressured. However, beneath 4,850 feet, the pore pressure gradient became over-pressurized having a pore pressure gradient of 0.88 psi/ft.[24] For the Beaufort Sea, a USGS report analyzed pressure data from five offshore wells and found that the pressures in the area where the wells were located were normally pressured (*i.e.,* at hydrostatic pressure) up to 2,000 feet subsea, and increased only slightly above hydrostatic pressure deeper into the well. By 10,000 feet, however, the pressure in all five wells were over-pressured, 1.5 times higher than the hydrostatic pressure.[25] Over-pressure started to occur at around 6,700 feet subsea.

While it is not possible to confirm that all targeted potential reservoirs would be shallow and normally pressured in all exploratory drilling situations, BSEE and BOEM will have access to the relevant geologic and geophysical information to help identify hydrocarbon bearing zones and zones with potential geologic risk, such as over-pressurized zones, that may be encountered during drilling operations. These higher pressured, hydrocarbon zones are, in fact, the targeted formations the industry has attempted to produce. For example, the BOEM report analyzing the Chukchi Sea's Burger gas discovery illustrated the regional geology of all the wells included in the study, and showed that the higher pressured zones in the wells occurred at the same point where the oil-bearing zones were located.[26] The Bureaus have the means, through access to relevant geological and geophysical (G&G) data and drilling application regulatory reviews, to confirm that operators identify and plan for these potential risks. For example, the bureaus confirm that operators have properly designed well casing and drilling programs and ensure that operators have access to properly designed equipment that is readily available to quickly respond to an incident, such as the availability of a capping stack in advance of drilling into the targeted productive zones.

4. Partnership With Alaska Natives in Northern Alaska

The bowhead whale provides the largest subsistence resource available to the native villages of Alaska's northern shores. In 1977, Eskimo whalers from these villages established the Alaska Eskimo Whaling Commission (AEWC), whose mission is to safeguard the bowhead whale and its habitat, defend the Aboriginal Subsistence Whaling Rights of their members, and preserve the cultural and traditional values of their villages. Eskimo whalers established the AEWC in response to actions taken by the International Whaling Commission (IWC) that resulted in the IWC's assumption of direct jurisdiction over the Alaskan Native bowhead whale subsistence hunt, without Alaska Native input. The IWC assumed direct jurisdiction over Alaska Native's bowhead whale subsistence in response to the IWC's concerns regarding the decline in the western Arctic bowhead whale stock. The IWC's only mechanism for protecting whale stocks is the setting of hunting quotas. Therefore, the IWC's only recourse for addressing its concerns was to prohibit the Alaska Native bowhead whale subsistence hunt. This action devastated local communities, creating immediate and severe food shortages. In response, in 1981, the AEWC was able to establish an agreement with the Federal Government to co-manage the bowhead whale hunting quotas.

Although the AEWC was able to regain control of its bowhead whale hunting quotas, the organization shared a similar concern with the IWC regarding the potential effects of offshore oil exploration and development on the bowhead whale. Whalers observed how bowhead whales were responding to the presence of ocean-going oil and gas industry exploration vessels, which were making the whales skittish and affecting the whalers' ability to effectively meet the quotas for their communities. In response, the AEWC worked with industry stakeholders to establish the ''Oil/Whaler Agreement,'' which was a communication plan between whalers and exploration vessels that was intended to prevent direct threats to the whalers' safety from industry vessels.

The AEWC and industry stakeholders eventually turned the ''Oil/Whaler Agreement'' into a framework for understanding and addressing indirect interference with hunting activities, resulting from behavioral changes in bowhead whales as they react to the noise and other pollutants accompanying oil and gas work. This framework of understanding eventually formed the basis of what is now known as a CAA.[27] While DOI does not require executing a CAA, BSEE and BOEM highly encourage operators to work with the AEWC to establish CAAs, since these agreements essentially acknowledge, within CAA provisions, that both subsistence hunting activities and oil and gas development can and should coexist. See discussion in *Section I.E.3, History and Background on the Conflict Avoidance Agreement,* of this preamble describing the provisions typically included in a CAA. This longstanding process allows for industry representatives to sit, in council, with members of the AEWC, local tribes, and village and regional corporations to determine cultural circumstances and situations that could cause conflict—and thus avoid them. For example, during whale (or walrus) hunting seasons in the spring and fall, the CAA may include provisions whereby industry will avoid construction or production noise and related activities during those times when whales are transiting nearby, and the hunters are in the area. With this early initiative, direct collaboration with local hunters, specifically the whaling captains and their representative organization, the AEWC, became a critical element of offshore industrial development planning and management in the Alaskan Arctic.

Today, the AEWC includes registered whaling captains and their crews from eleven whaling communities of the

area, Alaska: Regional geology, petroleum geology, environmental geology. U.S. Department of the Interior, Minerals Management Service, Alaska OCS Region, OCS Report MMS 85–0111. Anchorage, Alaska. *https://www.boem.gov/BOEM-Newsroom/Library/Publications/1985/85_0111.aspx.*

[24] Craig, J.D., & Sherwood, K.W., 2001 (revised 2004), ''Economic Study of the Burger Gas Discovery, Chukchi Shelf, Northwest Alaska,'' U.S. Department of the Interior, Minerals Management Service, p. 67, available online at *https://www.boem.gov/sites/default/files/boem-newsroom/Library/Publications/2004/Economic-Study-of-the-Burger-Gas-Discovery.pdf.*

[25] Hayba, D.O., Houseknecht, D.W., and Rowan, E., 1999, ''Stratigraphic, Hydrogeologic, and Thermal Evolution of the Canning River Region, North Slope, Alaska,'' U.S. Department of the Interior, U.S. Geological Survey, p. FF–21, available online at *https://pubs.usgs.gov/of/1998/ofr-98-0034/FF.pdf.*

[26] Craig, J.D., & Sherwood, K.W., 2001 (revised 2004), ''Economic Study of the Burger Gas Discovery, Chukchi Shelf, Northwest Alaska,'' U.S. Department of the Interior, Minerals Management Service, p. 72, available online at *https://www.boem.gov/sites/default/files/boem-newsroom/Library/Publications/2004/Economic-Study-of-the-Burger-Gas-Discovery.pdf.*

[27] Conflict Avoidance Agreements are contracts signed by the operators and the Alaska native communities to which BOEM is not a party.

Arctic Alaska coast: Gambell, Savoonga, Wales, Little Diomede, Kivalina, Point Hope, Point Lay, Wainwright, Barrow [28] (Utquiavik), Nuiqsut, and Kaktovik. The AEWC often represents the Inupiat Community of the Arctic Slope (ICAS) in matters pertaining to energy exploration or development specifically for the OCS. The ICAS is a unique federally recognized tribal entity. ICAS membership is based on an individual's ancestral lineage to a village tribe; it includes the peoples of eight Native Villages: Kaktovik, Atqasuk, Nuiqsut, Anaktuvuk Pass, Barrow, Wainwright, Point Lay, and Point Hope. Each village tribe acts independently but will interact with ICAS and its membership as it relates to Federal and State energy issues.

Conflict avoidance tools are often incorporated into leasing stipulations addressing consultation with subsistence communities, and will continue to be essential to help satisfy the need to provide a secure source of energy for the Nation while at the same time protecting the subsistence resources and uses of the local communities where these energy resources are located.

5. Industry Interest in the Arctic OCS

In 1979, a year after the first Arctic offshore discovery (*i.e.,* the Endicott oil field) was made in State waters, the Department, acting through the Bureau of Land Management (BLM), held the first oil and gas lease sale in the Arctic OCS, offering tracts adjacent to Prudhoe Bay in the Beaufort Sea Planning Area. That sale resulted in 24 leases, covering 85,776 acres, being issued. Although it was the first sale ever conducted for the Arctic OCS, the revenues generated from that sale, over $491 million, make it the 4th largest sale in Arctic OCS history. That dollar amount would represent almost $1.9 billion dollars in 2019 after adjusting for inflation. Between 1979 and 2008, the Department, acting through the BLM and Minerals Management Service (MMS),[29] held 13 oil and gas lease sales, and issued nearly 1,800 leases, covering over 9.7 million acres, on the Arctic OCS. These sales generated over $6.8 billion in bonus bids. As many as 23 companies/bidders have participated in an Alaska OCS lease sale and, while the number of companies/bidders participating from one sale to the next varied, an average of 10 companies/bidders participated in each sale.

By 2008, U.S. oil production had been steadily declining for 5 years to an average of 5 million barrels per day, while U.S. consumption of crude oil and petroleum products reached an all-time high of 20.68 million barrels per day.[30] The price of oil increased steadily through 2007 from approximately $50 to $90 per barrel by the time the most recent Arctic sale, Lease Sale 193, was held in February of 2008.[31] These market factors may have contributed to the outcome of Lease Sale 193, one of the most successful in Arctic OCS history, based on multiple metrics—the number of bids received, the number of tracts receiving bids, and the total amount of bonus bids received from the sale. The MMS received a total of 667 bids on 488 blocks; both record-setting numbers for the Arctic OCS. A total of 487 leases, covering over 2.7 million acres, were issued, and the sale generated over $2.6 billion in bonus bids, which went to the U.S. Treasury. Since 2008, however, the Department has not conducted any new lease sales for the Arctic OCS. A description of the status of active leases in the Artic OCS is discussed in further detail below within this subsection, prior to the subheading entitled, *Global Arctic Exploration Activities.*

Sale 193 was significant, not only in number of tracts sold and the amount received from the sale, but in that the industry's interest spurred a flurry of activities on the Arctic OCS prior to and after the sale. The following table lists those activities:

2006	
June 20	MMS authorizes ConocoPhillips, Shell, and GX Technology Corporation to conduct geophysical operations for a portion of Chukchi Sea Planning Area, which covered the Sale 193 area.
2007	
July 13	MMS authorizes Shell to conduct additional geophysical operations in Chukchi Sea Planning Area covering the same area as their 2006 geophysical permit.
2008	
February 6	MMS holds Chukchi Sea Lease Sale 193. Seven companies were issued leases from this sale—NACRA; Repsol; Shell; ConocoPhillips; Eni Petroleum; StatoilHydro; and Iona Energy Company.
February 15	MMS authorizes Shell to conduct even further geophysical operations, also covering the same area as their 2006 geophysical permit.
2009	
May 9	Shell submits its initial EP for the Chukchi Sea.
2010	
April 10	BP Deepwater Horizon Incident—Blowout of the Macondo well (Gulf of Mexico).
May 19	Secretary's Order 3299 reorganizing the Minerals Management Service and dividing its functions between three separate bureaus.
June 18	Secretary's Order 3302 creating the Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE).
August 8	BOEMRE authorizes Statoil to conduct geophysical operations within and around the area where their leases were located in the Chukchi Sea Planning Area.

[28] Although the Alaska Native tribe is based in Utquiavik, at any given time, the whaling may involve members of the Apugauti and Nalukatq tribes, whose native lands do not border the coast. For this reason, the AEWC prefers to refer to this group of whaling captains collectively by the broader term ''Barrow.''

[29] MMS was the predecessor agency of BSEE and BOEM.

[30] *https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MTTUPUS2&f=A,* table entitled, ''U.S. Product Supplied of Crude Oil and Petroleum Products (Thousand Barrels per Day)''.

[31] *https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=F000000__3&f=M.*

December 7	BOEMRE conditionally approves Shell's initial EP for the Chukchi Sea.
2011	
May 11	Shell submits a revised EP for the Chukchi Sea.
August 29	Secretary's Order 3299 was amended to divide BOEMRE into the Bureau of Ocean Energy Management (BOEM), the Bureau of Safety and Environmental Enforcement (BSEE), and the Office of Natural Resources Revenue (ONRR).
December 16	BOEM conditionally approves Shell's revised EP for the Chukchi Sea.
2012	
August 30	BSEE authorizes Shell to initiate certain limited preparatory exploration drilling activities; drilling of the top hole for Burger A exploration well in the Chukchi Sea.
September 9	Shell begins drilling operations for its Burger A exploration well in the Chukchi Sea, but was not able to complete its well operations. Shell returned in 2016 to complete its well operations, ultimately plugging and abandoning the well.
September 20	While not applicable to the Chukchi Sea, BSEE also authorizes Shell to initiate drilling of the top hole for the Sivuliq N exploration well in the Beaufort Sea.
October 3	Shell begins drilling operations for its Sivuliq N exploration well in the Beaufort Sea, but was not able to complete its well operations. Shell returned in 2016 to complete its well operations, ultimately plugging and abandoning the well.
2013	
August 5	BOEM authorizes TGS to conduct geophysical operations for a portion of Chukchi Sea Planning Area covering a portion of the Sale 193 area.
November 6	Shell submits a revised EP for the Chukchi Sea in response to lessons learned from its 2012 drilling operations of the Sivuliq N and Burger A exploration wells.
2014	
August 28	Shell submits a revised EP for the Chukchi Sea, replacing its November 2013 submission.
2015	
January 21	President Obama signed E.O. 13689, which calls for multiple agencies that may have jurisdictional responsibilities in the Arctic to enhance their coordination efforts to protect the nation's various interests in the region.
January 27	President Obama issues Presidential Memorandum withdrawing certain areas of the OCS within the Beaufort and Chukchi Seas from leasing. These areas included the Hannah Shoal in the Chukchi Sea and lease deferral areas identified in BOEM's 2012–2017 National OCS Oil and Gas Leasing Program.
February 24	BSEE and BOEM published the 2015 Proposed Arctic Exploratory Drilling Rule, providing a 90-day period for the public to review and comment on the proposed rule.
May 11	BOEM conditionally approves Shell's revised EP for the Chukchi Sea.
July 22	BSEE authorizes Shell to initiate certain limited preparatory exploration drilling activities; drilling of the top hole for Burger J exploration well in the Chukchi Sea.
July 31	Shell begins drilling operations for its Burger J exploration well in the Chukchi Sea.
September 21	Shell completes its Burger J exploration operations, and ultimately plugs and abandons the well.
October 16	The Department cancels all Beaufort and Chukchi lease sales that were scheduled to take place as part of BOEM's 2012–2017 National OCS Oil and Gas Leasing Program.
2016	
December 30	President Obama issues a Presidential Memorandum that expands the withdrawal to all areas of the Chukchi Sea planning area and much of the Beaufort Sea planning area that were not currently withdrawn at that time. The withdrawal excludes Beaufort tracts located nearshore in an area that included existing leases at the time.

A key factor that contributed to the length of time taken to authorize Shell's exploration drilling activities was a lawsuit filed by the Native Village of Point Hope challenging the Department's decision to hold Sale 193. *See Native Village of Point Hope* v. *Salazar,* 730 F. Supp.2d 1009 (D. Ak., 2010); *see also Native Village of Point Hope* v. *Jewell,* 740 F.3d 489 (9th Cir., 2014). The original Environmental Impact Statement (EIS) for Sale 193 was published in 2007, and the lease sale was held, but subsequent legal challenges and Federal court decisions remanded the lease sale to BOEM for further analysis. In response to the court remand, BOEM conducted additional analysis and incorporated that information into a Supplemental EIS that was published in February 2015 and affirmed the sale as held. Only thereafter were BOEM and BSEE able to complete their formal review of Shell's exploration plan for the Chukchi Sea and approve the drilling activities that took place in the summer of 2015.

Between 2008 and 2019, oil prices remained unstable, increasing to an all-time high of almost $96 per barrel in 2013 to $44 per barrel in 2015, which increased to $56 per barrel in 2019.[32] Domestic oil production had grown since 2008, in part due to developments in tight oil onshore and Gulf of Mexico production, to about 9.4 million barrels per day in 2015 and 12.2 million barrels in 2019.[33] Demand for oil remained relatively stable between 2008 and 2019, with only a minor increase in 2019 over 2008—approximately a 4% increase.[34]

On September 28, 2015, Shell announced that it would cease further exploration activity in offshore Alaska for the foreseeable future. Shell stated that its decision was based on the results of their Burger J well, which found indications of oil and gas, but were insufficient to warrant further

[32] *https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=F000000__3&f=M.*

[33] *https://www.eia.gov/todayinenergy/detail.php?id=4910.*

[34] *https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MTTUPUS2&f=A,* table titled ''U.S. Product Supplied of Crude Oil and Petroleum Products (Thousand Barrels per Day).

exploration in the Burger prospect. The company also stated that its decision was motivated by the high costs associated with the project, and the challenging and unpredictable Federal regulatory environment offshore Alaska.[35] On November 17, 2015, Statoil announced its decision to exit Alaska and relinquish its leases acquired from Sale 193. All leaseholders that acquired leases in Sale 193 eventually relinquished their leases.

Despite these setbacks, industry interest in the Arctic OCS and other areas of the Arctic, globally, has shown to be consistent amidst fluctuating commodity prices and concerns about regulatory challenges. Since 1998, nineteen geological and geophysical seismic surveys were permitted and completed for the Beaufort Sea and Chukchi Sea Planning Areas. The data from these surveys provide information to both industry and the government for use in lease sales and for design and evaluation of activities described in EPs and DPPs. Several different companies participated in each of the four Beaufort Sea Planning Area lease sales and the one Chukchi Sea Planning Area lease sale indicating on-going industry interest in the area. Companies submitted EPs, three in the Beaufort and one in the Chukchi Sea. These plans, and their revisions, received evaluation and conditional approval. BOEM approved two DPPs, both for the Beaufort Sea. Currently, there are 19 oil and gas leases in the Arctic OCS, all of which are located in the Beaufort Sea Planning Area. Exploratory drilling and development on these leases have taken place from gravel islands in State waters.

Global Arctic Exploration Activities

In addition to the Arctic OCS activities just described, global interest and development has taken place in other parts of the Arctic. Countries, such as Russia, Norway, Canada, and Greenland have been diligently exploring their oil and gas resources in or near the Arctic.

Greenland—Since the 1970s, exploration activities have taken place on the offshore waters of western Greenland. While these exploration activities have taken place in sub-Arctic regions, operators do experience some of the key challenges present in the Arctic. It is not uncommon for icebergs to pose dangers to drilling operations. Operators use ice management plans to identify, monitor, and tow away any icebergs that may impact their exploration operations. Operators also have contingency plans that may require disconnecting their drilling rig from the well and moving off location to avoid contact with icebergs.

Canada—In the Jeanne d'Arc, Orphan, and Flemish Pass oil and gas basins on the Grand Banks of Newfoundland, operators have conducted exploration drilling from MODUs in shallow and deep waters. Like Greenland, the areas with oil and gas potential are located in sub-Arctic regions that experience some seasonal sea ice and significant iceberg incursions. In these areas, operators also employ strong ice management and contingency plans.

Norway—In Norway's portion of the Barents Sea, which is located entirely within the Arctic, exploration activities have taken place since 1980. Most of the area is free of sea ice year-round, but drilling has taken place in areas that do experience challenging Arctic OCS conditions. As late as 2014, exploration drilling took place in Norway's northern portion of the Barents Seas in what is known as the Hoop area. Those exploration operations entailed the use of winterized semisubmersible rigs and the availability of a capping stack.

Russia—Russia's latest drilling operations also took place in 2014 when ExxonMobil drilled a well in the South Kara Sea. The operation took place in an area of the Arctic where drilling could not take place during the winter months, similar to the Chukchi and Beaufort Seas. Exploration activities took place during the summer, when little to no sea ice was present at the drilling location and were completed in mid-fall. The operation was similar to the operations from the other countries just described—a winterized MODU and robust ice management and contingency plans. However, unique to this project was the use of a subsea isolation device (SSID). (NPC Report 2015 at 6–17 and 6–18, and NPC Report 2019 at C–10). The Kara Sea project is discussed in more detail below in *Section II. Section-by-Section Discussion of Proposed Changes, Subsection A. Key Revisions Proposed by BSEE,* under the subheading entitled, *Supplemental Assessment to the 2015 Report on Arctic Potential: Realizing the Promise of U.S. Arctic Oil and Gas Resources (NPC 2019 Report).*

Global Arctic Exploration Requirements

Norway, Canada, and Greenland have similar regulatory requirements to the United States for Arctic offshore drilling operations performed from a MODU. The Bratslavsky and SolstenXP study also included a review of the regulatory requirements from these countries that pertain to relief wells, SCCE, and approval of alternative technologies. The study did not include Russia in its review because the country's regulations could not be accessed. Here is a summary of that review:

- *Relief Wells*—All the Arctic countries that were reviewed specifically require relief wells, but regulations among them differ. For example, Canada simply requires a ''same-season'' relief well capacity, whereby the operator demonstrates its capability to drill a relief well and kill an out-of-control well in the same drilling season. Whereas the U.S. requires the ability to bring in a relief-drilling rig and complete the plug and abandonment within 45 days, Norway and Greenland require a relief-drilling rig to be on site within 12 days.
- *SCCE*—Canada is the only country besides the U.S. that has specific SCCE requirements. Canada's requirements, however, are less prescriptive in that they include a more general requirement for ''cap and containment methods and same-well intervention methods,'' as compared to the U.S. requirement for access to specific SCCE equipment within a specified time period.
- *Alternative Technologies*—With respect to approval of alternative technologies in lieu of a relief rig or SCCE, the U.S. has specific regulations that allow for potential substitutions and accommodations for innovative technologies. Canada also provides for the approval of alternative technologies through specific approval processes. Norway's regulations, in general, are largely performance-based. As such, their regulations allow for the consideration of different technologies at the onset when planning a project.

B. BSEE and BOEM Statutory and Regulatory Authority and Responsibilities

The Outer Continental Shelf Lands Act, 43 U.S.C. 1331 *et seq.,* was first enacted in 1953 and substantially amended in 1978. In amending OCSLA, Congress established a national policy of making the OCS ''available for expeditious and orderly development, subject to environmental safeguards, in a manner which is consistent with the maintenance of competition and other national needs.'' (43 U.S.C. 1332(3)). OCSLA authorizes the Secretary of the Interior (Secretary) to lease the OCS for mineral development and to regulate oil and gas exploration, development, and production operations on the OCS.

On May 19, 2010, Secretary Ken Salazar issued S.O. 3299, which

[35] *https://www.shell.com/media/news-and-media-releases/2015/shell-updates-on-alaska-exploration.html.*

restructured and divided the former MMS's responsibilities under OCSLA among three new bureaus: (i) BOEM; (ii) BSEE; and the (iii) Office of Natural Resources Revenue (ONRR). S.O. 3299 delegated those responsibilities for oil and gas operations to BSEE and BOEM, both of which are charged with administering and regulating aspects of the Nation's OCS oil and gas program (see 30 CFR parts 250 and 550).

On June 18, 2010, Secretary Salazar issued S.O. No. 3302, which announced the name change of part of the former MMS to the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE). This name, BOEMRE, would remain in effect until BOEM and BSEE were officially created under S.O. 3299, effective October 1, 2011.

On October 1, 2010, the revenue-collection functions of the former MMS were transferred to ONRR, reporting to the Assistant Secretary for Policy, Management and Budget.

S.O. 3299 assigned BOEM the responsibility for managing the development of the Nation's offshore conventional and renewable energy resources. BOEM's mission is to manage the development of the OCS energy and mineral resources in an environmentally and economically responsible way. BOEM's functions include: Leasing; EP administration; DPP administration; permitting of geological and geophysical activities; environmental analyses in compliance with NEPA; environmental studies; compliance with relevant laws (*e.g.,* the Endangered Species Act (ESA), the Marine Mammal Protection Act, the Magnuson-Stevens Fishery Conservation and Management Act, and the Coastal Zone Management Act [36] (CZMA)); resource evaluation; oil spill worst case discharge (WCD) determination; economic analysis and fair market value bid/lease evaluations; management of the OCS renewable energy and marine mineral programs; and consultation with other entities at the local (*e.g.,* North Slope Borough, Native Villages), tribal (*e.g.,* Federally recognized tribes and Alaska Native Claims Settlement Act Corporations), State, and Federal levels (*e.g.,* National Oceanic and Atmospheric Administration (NOAA) Fisheries, U.S. Coast Guard (USCG)) related to activities within BOEM's activities and areas of responsibility.

Secretary's Order 3299 made BSEE responsible for safety and environmental enforcement functions, including, but not limited to, the authority to permit activities, inspect, investigate, summon witnesses and produce evidence: Levy penalties; cancel or suspend activities; and oversee safety, and oil spill response and removal preparedness. BSEE's mission is to promote safety, protect the environment, and conserve resources through vigorous regulatory oversight and enforcement. BSEE's functions include evaluating permit applications for post-lease oil and natural gas exploration and development activities on the OCS and conducting inspections to ensure compliance with laws, regulations, lease terms, and approved plans and permits.

BOEM evaluates EPs, and BSEE, thereafter, evaluates Applications for Permits to Drill (APDs) and other permits and applications, to determine whether the operator's proposed activities meet OCSLA's standards and each Bureau's regulations governing OCS exploration. Based on their respective evaluations, BSEE and BOEM will either approve the operator's EP and APD, require the operator to modify its submissions, or disapprove the EP or APD (§ 250.410, *How do I obtain approval to drill a well?*). The review and approval of these activities is outlined below in the following section.

1. BOEM Approval of the EP

As promulgated through the 2016 Arctic Exploratory Drilling Rule, § 550.204, *When must I submit my IOP for proposed Arctic exploratory drilling operations and what must the IOP include?,* requires that a lessee submit an IOP at least 90 days before filing an EP with BOEM, if that EP would involve exploration for oil and gas on the Arctic OCS. While the IOP is not subject to approval, the submission was intended to facilitate the prompt sharing of information among the relevant Federal agencies that may be involved in overseeing exploratory drilling operations conducted from MODUs. The operator may then submit an EP to BOEM for approval. An EP must include information such as a schedule of anticipated exploration activities, equipment to be used, the general location of each well to be drilled, and any other information deemed pertinent by BOEM (§§ 550.211 through 550.228).

2. BSEE Approval of the APD

Approval of an EP does not, by itself, permit the operator to proceed with exploratory drilling. After BOEM approves the EP, the operator must submit to BSEE an APD, which BSEE must approve before an operator may drill a well (43 U.S.C. 1340(d); § 250.410). Among other things, the APD must be consistent with the approved EP and include information on the well location, the drilling design and procedures, casing and cementing programs, the diverter and blowout preventer (BOP) systems, MODU (if one is to be used), and any additional information requested by the BSEE District Manager.

C. Executive and Secretary's Orders

On March 28, 2017, the President issued E.O. 13783—Promoting Energy Independence and Economic Growth (82 FR 16093). The E.O. directed Federal agencies to review all existing regulations and other similar agency actions, which potentially burden the development or use of domestically produced energy resources with the goal of ''avoiding regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation.'' It made it U.S. policy for agencies to ''review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise, or rescind those that unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law.''

On April 28, 2017, the President issued E.O. 13795—Implementing an America-First Offshore Energy Strategy (82 FR 20815), which directed the Secretary to ''take all steps necessary to review'' the 2016 Arctic Exploratory Drilling Rule and, ''if appropriate, [to,] as soon as practicable and consistent with law, publish for notice and comment a proposed rule suspending, revising, or rescinding this rule.'' The policy underlying E.O. 13795 is ''to encourage energy exploration and production, including on the Outer Continental Shelf, in order to maintain the Nation's position as a global energy leader and foster energy security and resilience for the benefit of the American people, while ensuring that any such activity is safe and environmentally responsible.'' These E.O.s did not dictate outcomes; rather, they provided direction for review in accordance with all relevant laws.

To further implement E.O. 13795, on May 1, 2017, the Secretary issued S.O. 3350, *America-First Offshore Energy Strategy,* directing BSEE and BOEM to review the 2016 Arctic Exploratory

[36] BOEM is not subject to the requirements of the CZMA in Alaska as it is on the rest of the OCS, where it is required to provide opportunities to the coastal State to review the proposed Federal actions for consistency with the state's federally approved coastal management program. More specifically, on July 1, 2011, Alaska repealed its CZMA program.

Drilling Rule ''for consistency with the policy set forth in section 2 of E.O. 13795'' and to prepare a report ''summarizing the review and providing recommendations on whether to suspend, revise, or rescind the rule.''

Consistent with E.O.s 13783 and 13795, and S.O. 3350, BSEE and BOEM reviewed the regulations promulgated through the 2016 Arctic Exploratory Drilling Rule and are proposing revisions to those regulations to reduce unnecessary burdens on industry while maintaining safety and environmental protection.

D. Purpose and Summary of the Rulemaking

BSEE and BOEM promulgated the 2016 Arctic Exploratory Drilling Rule based on experiences gained from Shell's 2012 and 2015 Arctic operations, internal reviews conducted on potential oil and gas operations on the Arctic OCS, and concerns expressed by environmental organizations and Alaska Natives.

Since publication of the 2016 Arctic Exploratory Drilling Rule, however, BSEE and BOEM have become aware of additional information informing and warranting the bureaus' reconsideration of certain regulatory provisions promulgated through that rule. BSEE commissioned a Technology Assessment Program study (Bratslavsky and SolstenXP, 2018) that entailed a historical statistical analysis of recent Alaska Arctic OCS drilling seasons (5-year period between 2012 and 2016), in which meteorology and physical oceanographic (''metocean'') and operational conditions would support the safe deployment of SCCE, the drilling of a relief well, or both. The study included a comprehensive review and gap analysis of U.S. and international regulations, standards, recommended practices, specifications, technical reports, and common industry methods regarding the safe deployment of SCCE, as compared to the effectiveness of drilling a relief well in Arctic conditions.

The Bratslavsky and SolstenXP study determined that metocean conditions prevalent in the Chukchi Sea and Beaufort Sea (*i.e.,* rough sea states and sea ice conditions, primarily) are key factors that limit the ability to safely deploy SCCE throughout the Arctic OCS. The study determined that, when operating in the presence of sea ice in the Chukchi Sea and the Beaufort Sea, there is a greater probability for safe relief well deployment versus SCCE deployment. When operating in open water conditions (*i.e.,* those prone to rough sea states) in the Chukchi Sea, there is also a greater probability for safe deployment of a relief rig versus SCCE. In the Beaufort Sea, the probability for safely deploying relief wells and SCCE is the same. This is because the Beaufort Sea has fewer ice-free days than the Chukchi and ice helps maintain calm sea state conditions.

The study also determined that water depth in the Arctic OCS is also a factor limiting the safe deployment of SCCE. According to the Bratslavsky and SolstenXP study, safe deployment of SCCE is likely to be impaired in water depths shallower than 984 feet because the equipment would potentially encounter a gas boil at the surface caused by a subsea blowing well (Bratslavsky and SolstenXP at 143). Water depths in the majority of the Chukchi Sea and Beaufort Sea where exploration has historically occurred are relatively shallow—167 feet or less (*id.* at 7 to 9). This water depth range limits the fleet of support vessels that could be used for the safe deployment of SCCE.

The NPC also published its NPC 2019 Report as a supplemental assessment to the NPC 2015 Report. The NPC prepared the NPC 2019 Report in response to an April 2018 request from the Secretary of Energy. The Secretary of Energy requested that the NPC provide recommendations for enhancing the Nation's regulatory environment by improving reliability, safety, efficiency, and environmental stewardship of oil and gas activities on the OCS. That report specifically addressed the regulatory burdens associated with U.S. Arctic OCS development.

Key findings from the NPC's supplemental assessment that helped inform the preparation of this proposed rule include the NPC's determination that the requirement to drill an SSRW to mitigate the risk of a late season well control event continuing over the winter season is ''outdated.'' The report concluded that SSIDs and capping stacks are superior solutions that could stop the flow of oil and allow intervention through the original borehole before a relief well could be completed (NPC 2109 Report at 19). Details in the report regarding Russia's 2014 drilling operation that included the use of an SSID in the South Kara Sea also informs this proposed rule.

In this proposed rule, the Bureaus also address other issues in addition to those addressed in the 2016 Arctic Exploratory Drilling Rule, including seasonal weather-related constraints in the Arctic that severely impact an operator's ability to safely perform leaseholding operations for a significant portion of the term on a lease. While these issues are in addition to the issues addressed by the 2016 Arctic Exploratory Drilling Rule, they are unique to the Arctic OCS and, therefore, are appropriate to address as part of this proposed rulemaking.

BSEE and BOEM recognize that the 2016 Arctic Exploratory Drilling Rule addressed specific operational and environmental conditions that are unique to the Arctic OCS. While this proposed rule would leave most of the regulations promulgated by the 2016 rule unaltered, certain of these regulations are worth reconsidering to accommodate technological innovation and encourage energy exploration on the Arctic OCS. Based on the new scientific information gathered from the Bratslavsky and SolstenXP study, and global practical experience gained in recent years, as described in the NPC Reports, the bureaus believe that these proposed revisions reduce unnecessary regulatory burdens on stakeholders and increase the ability to review and apply advancing technological innovations, while ensuring safety and environmental protection.

The following paragraphs briefly summarize the key elements of this proposed rule, which are more fully explained in *Section II. Section-by-Section Discussion of Proposed Changes* of this preamble:

1. Seasonal Conditions SOO—The unique seasonal conditions in the Arctic make it difficult or physically impossible for operators to explore their leases for a significant portion of each year. To facilitate the proper development of Arctic leases in accordance with OCSLA sec. 5,[37] BSEE proposes to add a new provision to its regulations that would provide those operators that are conducting drilling operations, but are prevented from completing those leaseholding operations due to seasonal constraints unique to the Arctic, with the opportunity to obtain an SOO. If granted, this type of SOO would suspend the running of the lease term and effectively extend the term of the affected lease by a period equivalent to the period of such suspension. This would provide operators that are otherwise ready and able to conduct drilling operations with additional time to diligently explore their leases, without facing lease expiration due to

[37] OCSLA sec. 5 (as amended) provides in pertinent part: ''The regulations prescribed by the Secretary . . . shall include . . . provisions . . . for the suspension . . . of any operation or activity . . . at the request of a lessee, in the national interest, [or] to facilitate proper development of a lease . . . and for the extension of any permit or lease affected by [such] suspension . . . by a period equivalent to the period of such suspension . . . .'' 43 U.S.C. 1334(a)(1).

interference by seasonal constraints unique to the Arctic.

2. Water-Based Mud and Cuttings—BSEE proposes to eliminate references to the Regional Supervisor's discretionary authority to require the capture of water-based muds and cuttings in those cases where subsistence values might be impacted by such discharges. While not intended, BSEE understands that this reference created some uncertainty for the regulated industry, because it appeared to overlap with regulation by the Environmental Protection Agency (EPA) and, if implemented, might result in BSEE issuing requirements that contradict EPA's requirements.

3. SCCE—BSEE would preserve the requirement for the operator to have access to its SCCE when drilling below or working below the surface casing. However, with respect to the capping stack, the Bureau proposes to provide an opportunity to the operator to adjust the point in time during operations when it must position its capping stack so that it is available to arrive at the well location within 24 hours after a loss of well control. The existing regulations also impose a positioning requirement on the cap and flow system, and containment dome—slightly different from the capping stack—''positioned to ensure that it will arrive at the well location within 7 days after a loss of well control.'' BSEE's proposed changes to the positioning requirement for the cap and flow system and containment dome are discussed in more detail later in this paragraph. If the operator is able to demonstrate to BSEE, based on documentation it submits as part of its APD, that the operations it plans to conduct below the surface casing would not encounter any abnormally high-pressured zones or other geological hazards before reaching the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities, then BSEE will allow the operator to delay its positioning of the capping stack until reaching that casing point. BSEE's proposal to delay the positioning of the capping stack would be based on the documentation that the operator provides as well as any other available data and information. As previously mentioned, BSEE also proposes to eliminate the requirement for the operator to ensure that the containment dome and cap and flow system are positioned so as to arrive at the well location within seven days after a loss of well control. The Bratslavsky and SolstenXP study evaluated current industry methods and standards for deploying SCCE in Arctic OCS conditions, and determined that meteorological conditions (*e.g.,* rough sea state and sea ice conditions) prevalent in the Chukchi Sea and Beaufort Sea are the key factors limiting the time periods when SCCE may be safely deployed throughout the Arctic OCS. This is discussed in further detail below in *Section II. Section-by-Section Discussion of Proposed Changes,* under the subheading *What are the requirements for Arctic OCS source control and containment? (§ 250.471).* It is not practical for BSEE's regulations to prescribe that certain SCCE (containment dome and cap and flow system, in particular) be positioned within proximity to a well location when the conditions for safely deploying this equipment in the Arctic OCS are limiting. However, BSEE would retain other existing containment dome and cap and flow system requirements in § 250.471, which provide that the operator must:

(i) Demonstrate that it has access to a containment dome and cap and flow system;

(ii) Provide a containment dome and cap and flow system that meets BSEE's operating standards;

(iii) Conduct tests or exercises for all SCCE; and

(iv) Maintain records pertaining to the testing, inspection, maintenance, and use of the SCCE and make these available to BSEE upon request. The changes BSEE proposes to the SCCE requirements in § 250.471 would preserve the regulations' requirement that operators have redundant protective measures that are appropriate for Arctic OCS conditions because there is no guarantee that a single measure could control or contain a WCD.

4. Same Season Relief Well (SSRW) Requirement and Subsea Isolation Devices (SSID)—BSEE proposes to revise the relief rig and SSRW requirements by providing the operator with the option of using an SSID or having access to a relief rig as an additional means to secure the well in the event of a loss of well control, if the operator will be conducting exploratory drilling operations from a MODU. In addition, BSEE proposes to provide an opportunity to the operator to adjust the point in time during operations when it must stage its relief rig (if the operator elects to have access to a relief rig) when conducting Arctic OCS exploratory drilling operations—from when drilling below or working below the ''surface casing'' to when drilling below or working below the ''last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities.'' If the operator is able to demonstrate to BSEE, based on documentation it submits as part of its APD, that the operations it plans to conduct below the surface casing would not encounter any abnormally high-pressured zones or other geological hazards before reaching the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities, then BSEE will allow the operator to delay its staging of the relief rig until reaching that casing point. BSEE's proposal to permit the delay of the staging of the relief rig will be based on the documentation that operator provides, as well as any other available data and information. In the relief rig and SSRW regulation, BSEE would also eliminate the reference to expected seasonal ice encroachment because the relevant timeframes for operations should be based on the capabilities of the operator's rig and equipment to operate in the applicable ice conditions, rather than an absolute date.

5. Mudline Cellars—BSEE proposes to clarify the requirement for the operator, in areas of ice scour, to use a mudline cellar when drilling that is designed to minimize the risk of damage to the well head and wellbore. The existing regulation could be read to require the operator to use a mudline cellar in all cases, except when the operator can prove that the mudline cellar would present an operational risk, and that was not BSEE's intent. This proposed change would make it clear that the operator has more flexibility to propose to employ alternate procedures or equipment instead of the mudline cellar under appropriate circumstances, as provided by the longstanding provisions of § 250.141, *May I ever use alternate procedures or equipment?;* not just when a mudline cellar would present an operational risk and if the operator is able to demonstrate that the alternate procedure or equipment would provide a level of safety and environmental protection that equals or surpasses the mudline cellar requirement.

6. IOP—BOEM proposes to eliminate the requirement that the operator submit an IOP because it requires submission of information that overlaps with that required in the EP and the IOP's early information sharing is unnecessary in light of BOEM's practice for reviewing and coordinating review of the EP. Consequently, the operator is already aware that it must plan for how it will reduce operational risks and address the challenges associated with operations on the Arctic OCS through its EP.

E. Partner Engagement in Preparation for This Proposed Rule

1. Summary of Partner Interaction

In advance of publishing this proposed rule, BSEE and BOEM reached out to Alaska Native tribal leaders, ANCSA corporations, and native village leaders in Northern Alaska for Government-to-Government consultations and municipal meetings. These Bureaus arranged consultations and meetings to receive input from these groups on potential regulatory changes that could encourage energy exploration and production and reduce unnecessary regulatory burdens, while maintaining safety and environmental protection. Between November 29, 2018 and January 30, 2019, BSEE and BOEM officials met with 23 tribal, ANCSA corporation, and municipal leaders at villages throughout Northern Alaska (Kotzebue, Point Hope, Utqiagvik [*i.e.,* Barrow], Nuiqsut, and Kaktovik), in Fairbanks, and in Anchorage. In addition, BSEE and BOEM held a consultation meeting via a conference call with tribal representatives from the Native Village of Point Lay. The following list identifies the entities with which BSEE and BOEM met:

- Tribal Governments—Native Village of Utqiagvik, Native Village of Wainwright, Native Village of Kotzebue, Native Village of Point Hope, Native Village of Nuiqsut, Native Village of Kaktovik, Tanana Chiefs Conference, and Native Village of Point Lay;
- Native Corporations—Olgoonik Native Corporation, Doyon Limited, Arctic Slope Regional Corporation, Tikigaq Native Corporation, Cully Corporation, Kuukpik Corporation, and Kaktovik Inupiat Corporation;
- Municipal Governments—Northwest Arctic Borough, Point Hope, North Slope Borough, City of Utqiagvik, Nuiqsut, and Kaktovik; and,
- Other Tribal Organizations—ICAS and the AEWC.

BSEE and BOEM shared information with the tribal representatives describing potential options for regulatory change that the Bureaus were considering at the time the meetings took place. BSEE and BOEM made multiple attempts to contact two corporations—Kikiktagruk Corporation and NANA Regional Corporation but did not receive a response from them.

2. Summary of Comments Received

BSEE and BOEM heard a variety of perspectives during these meetings with Alaska Natives. The most common comment received was a concern over food security. Subsistence resources, including bowhead and beluga whales, other marine mammals, fish, and birds, are a key food source for many peoples' diets in the native villages. The Alaska Natives' primary concerns pertained to protecting their food sources. BSEE and BOEM are fully aware that subsistence resources play a key role in offsetting the high costs of conventional food supplies and that subsistence hunting and fishing play a key role in the cultural identity of Alaska Natives. BOEM's leases all contain provisions related to the protection of these subsistence uses and BOEM's regulations at §§ 550.227(b)(7) and 550.261(b)(7) require lessees to explain how they propose to protect these subsistence uses. In addition, BSEE and BOEM are not proposing any regulatory changes that would adversely affect protection of subsistence uses.

Certain tribal representatives, and most ANCSA corporations, were supportive of this rulemaking, and explained that it could help attract more economic opportunities to their villages. In some cases, tribes or corporations advocated for the use of their villages to support safer oil and gas operations, because the villages have deeper ports that could support larger vessels, or because they may be located closer to potential drilling operations than those ports or facilities that have been used in the past. This could allow for quicker response to emergency incidents.

BSEE did not include any regulatory changes in this proposed rule specifically designed to respond to this comment. While requiring the staging of equipment at strategically located coastal depots could have a positive impact on oil spill responses in the Arctic, the identification and placement of depots for such resources falls to the discretion of the operator (within the parameters established by existing regulation). To provide each plan holder with the flexibility needed to respond to their WCD scenarios, BSEE's Oil Spill Response Plan (OSRP) regulations do not mandate the use of any particular staging location(s) for equipment and personnel. BSEE will review the operator's staging arrangements submitted as part of the proposed OSRP to ensure that the OSRP would fully comply with the planning requirements in the governing regulations.

Other comments provided during the consultation meetings included a recommendation for BSEE and BOEM to provide broader outreach by presenting this proposed rule to their tribal assembly and to citizens within the communities.

DOI strives to strengthen its government-to-government relationship with federally recognized tribes through a commitment to consultation with tribes and recognition of their right to self-governance and tribal sovereignty. E.O. 13175, *Consultation and Coordination with Indian Tribal Governments* and DOI's tribal consultation policy, which implements the E.O., provide for procedures for consultation with tribes when taking an action with tribal implications. DOI has extended its consultation policy to ANCSA corporations. Furthermore, BSEE and BOEM recently issued their own expanded tribal consultation guidance on August 20, 2019 and June 29, 2018, respectively. BSEE's guidance (*Bureau of Safety and Environmental Enforcement (BSEE) Tribal Consultation Guidance,* August 20, 2019, available at *https://www.bsee.gov/bsee-tribal-guidance-2019*) and BOEM's guidance (*BOEM Tribal Consultation Guidance,* June 29, 2018, available at *https://www.boem.gov/Tribal-Engagement/*), identify various consultation authorities that BSEE and BOEM will follow in consulting with tribes and ANCSA corporations.

DOI recognizes and respects the distinct, unique, and individual cultural traditions and values of Alaska Native people and the statutory relationship between ANCSA Corporations and the Federal Government. BSEE and BOEM will endeavor to go above and beyond their consultation responsibilities where and when appropriate throughout the rulemaking process to maintain a strong working relationship with their tribal and ANCSA corporation partners.

BSEE and BOEM also received a comment from one of the ANCSA corporations recommending that this rulemaking take into account the NPC 2019 Report. BSEE and BOEM considered the NPC reports when preparing this proposed rule and based some of the proposed regulatory revisions on that report's recommendations, as discussed more fully below.

Another common comment that BSEE and BOEM received was a recommendation to include a requirement for a CAA between the oil and gas operator and those whaling communities potentially affected by an operator's proposed drilling project. A CAA is typically established through a collaborative process whereby both parties work to create mitigation strategies that would avoid adverse impacts to bowhead whales and other marine mammals, their habitat, and hunting opportunities. Historically, operators have voluntarily used the CAA process and, currently, existing lessees are required to do so through lease stipulations.[38] See discussion in *Section I.E.3, History and Background on the Conflict Avoidance Agreement,* of this preamble describing the history and background of the CAA. In addition, under the MMPA, the taking of marine mammals without a permit or exception is prohibited in order to prevent the decline of species and populations. To avoid liability for take, operators must obtain an Incidental Take Authorization or Incidental Harassment Authorization for activities related to offshore exploration, development and production. Implementation of the MMPA is shared between NMFS and USFWS.

Section 7(a)(2) of the ESA requires every Federal agency to ensure that any action they authorize, fund, or carry out is not likely to jeopardize the continued existence of a listed species or result in the adverse modification of designated critical habitat. When any exploration or development plan, or G&G permit application, is submitted to BOEM, BOEM evaluates the proposal, and consults with NMFS and USFWS on species listed under the ESA. During this process, mitigation measures (*e.g.,* vessel speed restrictions, rig lighting specifications, and protected species observer requirements) are developed to reduce impacts to protected species. These measures are then included in BOEM's conditions of approval for the EP, DPP, or G&G permit.

BOEM did not include any regulatory changes in this proposed rule specifically designed to respond to this comment. BOEM cannot require whaling communities to establish agreements with operators, since BOEM has no jurisdiction over such communities. Such a requirement for lessees and operators to execute an agreement could give a third-party power to set conditions for, or veto, OCS activities over which they otherwise have no authority.

[38] Every BOEM Arctic lease contains a variant of the following stipulation: ''Prior to submitting an exploration plan or development and production plan (including associated oil-spill contingency plans) to MMS for activities proposed during the bowhead whale migration period, the lessee shall consult with the directly affected subsistence communities, Barrow, Kaktovik, or Nuiqsut, the North Slope Borough (NSB), and the AEWC to discuss potential conflicts with the siting, timing, and methods of proposed operations and safeguards or mitigating measures which could be implemented by the operator to prevent unreasonable conflicts. Through this consultation, the lessee shall make every reasonable effort, including such mechanisms as a conflict avoidance agreement, to assure that exploration, development, and production activities are compatible with whaling and other subsistence hunting activities and will not result in unreasonable interference with subsistence harvests.

A discussion of resolutions reached during this consultation process and plans for continued consultation shall be included in the exploration plan or the development and production plan. In particular, the lessee shall show in the plan how its activities, in combination with other activities in the area, will be scheduled and located to prevent unreasonable conflicts with subsistence activities.''

For those reasons, BOEM has concluded that a regulation would not result in any additional protections of subsistence whaling beyond those provided by its longstanding practice of addressing the issue in a lease stipulation. BOEM has included as a lease stipulation for all Arctic OCS lease sales since 1991 that the lessee must make every reasonable effort, including such mechanisms as a CAA, to assure that exploration, development, and production activities are compatible with whaling and other subsistence hunting activities and will not result in unreasonable interference with subsistence harvests. Implementation of the stipulation must be described in an EP under § 550.222. In addition, either BOEM or BSEE may require additional mitigation measures at the EP or the APD stages, as necessary, to appropriately address potential interference with subsistence activities. For example, because subsistence hunters are concerned that the effects of offshore oil and gas exploration might displace migrating bowhead whales and other marine mammals (like beluga whales), the Bureaus will meet with the AEWC and its whaling captains to help document traditional knowledge pertaining to bowhead whales, including movement and behavior.

Given the importance of subsistence activities and related socio-cultural activities to the Alaska Native communities, BOEM has long encouraged operators to work directly with interested parties to help mitigate potential impacts to subsistence activities. In addition, BOEM funds and supports studies to better understand the potential impacts from OCS operations on marine mammals and subsistence activities. Over the last 46 years, the environmental studies program has provided more than $1.2 billion nationally for scientific research on the OCS. Nearly $500 million of that amount has funded studies in Alaska to produce more than 1,000 technical reports and innumerable peer reviewed publications. BOEM uses information from the studies program to evaluate the potential environmental effects of leasing OCS lands for exploration and development. Since July 2016, BOEM has completed 35 environmental studies and has 23 ongoing studies that cover the Arctic, totaling nearly $72 million. While environmental conditions change and continue to change (*e.g.,* walrus habitat, bowhead whale migration, and ice coverage), BOEM's environmental studies program both adds to our understanding and tracks these changes to have the best science available for the public, industry, and federal permitting decisions. While BOEM has observed changes through these studies, these changes follow the trajectory that BOEM has been studying and documenting for several decades. While this proposed rule would change how operators could explore for OCS resources in the Arctic, there are ample opportunities to permit these activities consistent with ESA, MMPA, NEPA, and consultation with Alaska Native communities.

3. History and Background on the Conflict Avoidance Agreement

In 1977, the IWC expressed concern over the low bowhead whale population. Its report specifically mentioned that the future expansion of offshore oil and gas extraction in the Arctic posed a potential risk to the bowhead whale population. At that time, Inuit subsistence hunters knew that bowhead whales were sensitive to anthropogenic noise, movements, and even smells. There were concerns that increased activity would affect their hunt. Traditional hunters had noticed that boat traffic, seismic exploration, and drilling were causing migrating whales to deflect away from the shore and beyond the hunters' reach.

Beginning in 1986, offshore stakeholders, such as representatives from whaling villages, the AEWC, and oil and gas companies, have all met to identify sources of potential conflict, and have relied on local traditional knowledge as well as other information. CAAs were developed first in the 1980s to address these sources of potential conflict and have been referenced in lease stipulations since 1991.

Since 1991, all leases in the Arctic issued by BOEM or its predecessors have included a stipulation requiring the operator to coordinate their activities with potentially affected Alaska native communities. While the text of these stipulations has varied from time to time, all of them have included certain important components. The following is an extract from such a stipulation, incorporated into the leases issued from the Oil and Gas Lease Sale Number 202, issued on April 18, 2007:

> Prior to submitting an exploration plan or development and production plan (including associated oil-spill contingency plans) to MMS for activities proposed during the bowhead whale migration period, the lessee shall consult with the directly affected subsistence communities, Barrow, Kaktovik, or Nuiqsut, the North Slope Borough (NSB),

and the Alaska Eskimo Whaling Commission (AEWC) to discuss potential conflicts with the siting, timing, and methods of proposed operations and safeguards or mitigating measures which could be implemented by the operator to prevent unreasonable conflicts. Through this consultation, the lessee shall make every reasonable effort, including such mechanisms as a conflict avoidance agreement, to assure that exploration, development, and production activities are compatible with whaling and other subsistence hunting activities and will not result in unreasonable interference with subsistence harvests.

Because this stipulation was provided for in the lease sale notice and included in the lease agreements resulting from the lease sale, its requirements became binding for all leases issued as a result of that particular lease sale.

The intent of this stipulation is for the operator to make a reasonable effort to establish a CAA with potentially affected whaling or subsistence hunting communities. It is the operator's responsibility to attempt to reach agreement on a CAA with those communities.

II. Section-by-Section Discussion of Proposed Changes

This section provides explanations of and justifications for each of the specific regulatory changes proposed in this document. Since this is a joint BSEE and BOEM proposed rulemaking, this Section-by-Section discussion is organized according to the order in which the relevant provisions would appear in the CFR. BSEE's and BOEM's regulations are found in the CFR at Title 30—Mineral Resources, Volume 2; BSEE's regulations are in Chapter II, and BOEM's regulations are in Chapter V.

A. Key Revisions Proposed by BSEE

Title 30, Chapter II, Subchapter B, Part 250

Subpart A—General

Definitions. (§ 250.105)

BSEE proposes to revise the definition of *Capping Stack* by deleting the phrase ''including one that is pre-positioned'' from the definition. BSEE included this phrase as part of the 2016 Arctic Exploratory Drilling Rule in response to a suggestion that the definition in the 2015 Arctic Proposed Rule should be expanded to allow pre-positioned capping stacks to be used below subsea BOPs when deemed technically and operationally appropriate. Recognizing that the comment was helpful, BSEE agreed with the suggestion and added the phrase ''including one that is pre-positioned'' to the capping stack definition (*see* 81 FR 46492). As a practical matter, pre-positioned capping stacks are similar to SSIDs. Accordingly, this modification in the 2016 final rule effectively allows the operator to install an SSID below a subsea BOP and would be in compliance with the capping stack requirement in the existing § 250.471, *What are the requirements for Arctic OCS source control and containment?* Existing § 250.471(a)(1), specifically requires the operator, when drilling below or working below the surface casing, to have access to a capping stack that is positioned to ensure that it will be able to arrive at the well location within 24 hours after a loss of well control. Typically, an operator would comply with this requirement by having one or more support vessels capable of handling and deploying the capping stack down to the subsea wellhead, when needed. Installing an SSID below the subsea BOP allows the operator to comply with § 250.471(a)(1) and forgo the need to provide support vessels and a capping stack on standby at the surface.

However, BSEE is proposing to eliminate this language because a pre-positioned capping stack is a piece of equipment that, as previously mentioned, aligns closely with an SSID. The Bureau is currently proposing distinct SSID requirements under § 250.472, *What are the additional well control equipment or relief rig requirements for the Arctic OCS?* This proposed revision would provide clarity concerning the capping stack requirements under § 250.471, specifically that installation of an SSID under § 250.472 does not constitute compliance with the capping stack requirements under § 250.471. For purposes of BSEE's proposed regulations, an SSID is not considered to be the same as, or to satisfy the requirement to have, a capping stack. The new SSID option that BSEE is proposing under § 250.472 does not, and is not intended to, replace any of the SCCE requirements in proposed § 250.471(a), where BSEE's capping stack requirement is addressed.

When may the Regional Supervisor grant an SOO? (§ 250.175)

BSEE proposes to revise § 250.175 by adding a new paragraph (d), which would allow an operator to request an SOO under certain situations that may be present in the Arctic OCS. This proposed revision is consistent with OCSLA's requirement that the Secretary promulgate suspensions regulations that ''facilitate proper development of a lease . . . .''[39] The proposed regulation would list the factors upon which BSEE may rely when determining whether to grant an SOO and include when an operator:

(1) Has conducted operations on the lease during the drilling season immediately preceding the period for which the operator is seeking a suspension;

(2) is drilling from: A MODU, an artificial gravel island or a gravity-based structure, or an artificial ice island; and

(3) is not able to safely continue its operations due to the presence of seasonal ice, temporary seasonal drilling restrictions in its approved oil spill response plan, or seasonal temperature changes (respectively, for each facility type).

Currently, BOEM issues Alaska OCS leases with the maximum 10-year primary lease term allowed under OCSLA.[40] However, operators may be precluded from properly developing leases because it is not possible to conduct leaseholding operations for significant portions of those 10-year terms. Offshore drilling locations on the Arctic OCS are inaccessible for a significant portion of each year, due to seasonal changes that make operating conditions unsafe or otherwise preclude operations. Moreover, it is difficult to predict precisely when sea ice will persist or break-up.

MODUs—For example, drilling operations performed from a MODU may occur only during the open-water drilling season (generally late June to early November), when sea ice is non-existent or minimal. This practical limitation, without considering other logistical problems unique to the Arctic OCS, could mean that during a consecutive 10-year period, a lease may be unavailable for operations for approximately 70 percent of the time.

Artificial Gravel Islands or Gravity-based Structures—Drilling from artificial gravel islands and gravity-based structures is prohibited during the spring/summer ice break-up and the fall/early winter freeze-up periods, because of the potential impact of weather and ice conditions on potential oil spill response and cleanup efforts. In particular, response and cleanup techniques for a large spill are not as effective when sea ice is broken and unconsolidated around the drilling location. By contrast, response and

[39] OCSLA sec. 5, as amended, codified at 43 U.S.C. 1334(a)(1).

[40] OCSLA sec. 8, as amended, states in part: ''An oil and gas lease issued pursuant [OCSLA] shall be for an initial period of (A) five years; or (B) not to exceed ten years where the Secretary finds that such longer period is necessary to encourage exploration and development in areas because of unusually deep water or other unusually adverse conditions . . . .'' 43 U.S.C. 1337(b).

cleanup efforts for a large oil spill from an artificial gravel island or a gravity-based structure could be executed effectively during the summer (*i.e.,* in open-water conditions) using existing oil spill response technologies. During the winter (*i.e.,* under solid ice conditions), the ice, and any snow on the ice, could provide an effective platform for oil spill response and cleanup efforts, and help absorb the spill and contain it to an area relatively close to the gravel island or gravity-based structure. Land-based equipment could then be used to collect and transport the oil-covered ice out of the location. For context, a gravity-based structure would include a concrete island drilling structure and a steel drilling caisson(s).

Artificial Ice Islands—A similar issue would be encountered if drilling were to take place from a man-made ice island. In those cases, the drilling location would be accessible only during the winter season when temperatures are very low, and the area is completely covered by ice stable enough to safely support a drilling rig and associated equipment. As temperatures rise during the spring and summer seasons, the ice breaks or melts away, making the drilling location inaccessible until the next winter season.

The new paragraph (d) of § 250.175 would facilitate the proper development of a lease by addressing those seasonal conditions that limit leaseholding operations by providing an operator ready and able to complete its operations with the opportunity to obtain an SOO. If granted, this SOO would suspend the running of the lease term and effectively extend the term of the affected lease by a period equivalent to the period of such suspension. The SOO would allow a diligent operator to use the full 10 years in a 10-year lease term to explore for hydrocarbons, without the concern for a lease expiring because Arctic seasonal constraints prevented operations.

BSEE would continue to require the operator to comply with the existing requirements for requesting a suspension under existing § 250.171, *How do I request a suspension?* For example, § 250.171 requires the operator to submit a reasonable schedule of work for resuming the suspended operations on the subject lease for which the operator requests the suspension. A schedule of work typically includes milestones describing what activities the operator will perform to resume operations and when those operations will be performed. If the operator submits a schedule of work that demonstrates a reasonable plan and schedule for resuming operations, BSEE will typically grant the SOO (assuming the other requirements are satisfied). BSEE will use the reasonable schedule of work as an established measuring stick by which the Bureau would assess the operator's diligence and progress toward prudent development. If the operator does not adhere to its approved work schedule, BSEE may terminate the SOO under existing regulations. Paragraph (e) of existing § 250.170, *How long does a suspension last?* authorizes BSEE to terminate any suspension when the Regional Supervisor determines the circumstances that justified the suspension no longer exist. Because a reasonable schedule of work serves as a required foundation for BSEE's SOO approval, the operator's adherence to that schedule is necessary to maintain the SOO. This allows BSEE to ensure that the operator complies with the OCSLA Congressional declaration of purpose. Other regulations under Subpart A that would also apply to BSEE's implementation of proposed paragraph (d) of § 250.175 includes § 250.170, *How long does a suspension last?* which allows BSEE to issue a suspension for up to five years and provides that the suspension automatically ends when the suspended operation commences.

BSEE understands the requirement in OCSLA to supervise operations in a manner that assures due diligence in the exploration and development of each lease. Therefore, BSEE is contemplating the option of limiting the period for when the suspension would remain in effect; only during the period between one drilling season and the next when the operator is prevented from continuing its drilling or other leaseholding activities due to seasonal conditions. This option would still provide operators more time to effectively explore their leases without fear of an expiring lease. It could also provide BSEE with a better means of tracking an operator's diligence efforts. This option, however, could result in additional unnecessary burdens, since an operator would have to ''reapply'' for a new suspension if the operator is unable to return to the location during the next open-water season. BSEE is seeking comment on this regulatory option for the SOO or any other option that could avoid or minimize additional burden, but still assure diligent lease exploration and development.

BSEE's proposed regulatory change would address concerns raised in the NPC reports, which suggested that the current approach toward administration of the 10-year primary lease term allowed under OCSLA ''comes from other offshore areas in the U.S., where operators have access to the leases all year-round.'' (NPC 2015 Report at 31 and NPC 2019 Report at 25). The NPC 2019 Report pointed out that a ''10-year lease in the U.S. Arctic equates to about 3 to 4 years of working time, compared with the equivalent 10 years working time in the Gulf of Mexico.'' (NPC 2019 Report at 25). While it is not possible for BOEM to award leases with more than the maximum ten-year primary lease term allowed under OCSLA, this proposed regulatory change would rely on the Secretary's statutorily delegated authority, which has, in turn, been delegated to BSEE, to administer suspensions to address, as appropriate, the effects of Arctic working conditions when they may limit the operator's ability to perform leaseholding activities.

Documents Incorporated by Reference. (§ 250.198)

BSEE proposes to revise the existing relief rig and SSRW requirements in § 250.472 by providing the operator with an option to either use an SSID or have access to a relief rig if the operator will conduct exploratory drilling operations from a MODU. As part of that proposed regulatory change, which is discussed in detail later below in the *What are the relief rig or additional well control equipment or relief rig requirements for the Arctic OCS? (§ 250.472)* section-by-section discussion, BSEE proposes to require the SSID to include Remotely Operated Vehicle (ROV) intervention equipment that has the capabilities to function the SSID. Under proposed § 250.472(a)(3)(ii), BSEE would require the ROV to have panels that are compliant with API RP 17H, *Remotely Operated Tools and Interfaces on Subsea Production Systems,* Second Edition, June 2013; Errata, January 2014, to ensure that the operator's ROV capabilities for the SSID follow BSEE's existing ROV panel requirements for BOP systems. In conjunction with proposed paragraph (a)(3)(ii) that would require the operator's ROV panels to be compliant with API RP 17H, BSEE proposes to add the citation for proposed § 250.472(a)(3) to § 250.198(e)(73). Paragraph (e)(73) of § 250.198 documents the locations in the regulations where API RP 17H is incorporated by reference as a regulatory requirement, which would include § 250.472(a)(3) under this proposed rule. Adding the citation for § 250.472(a)(3) to § 250.198(e)(73) would clarify that API RP 17H is a regulatory requirement when complying with § 250.472 and is subject to BSEE oversight and enforcement in the same manner as other regulatory requirements.

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

This recommended practice provides general recommendations and overall guidance for the design and operation of remotely operated tools (ROT) and remotely operated vehicle (ROV) tooling used on offshore subsea systems. ROT and ROV performance is critical to ensuring safe and reliable subsea operations and this document provides general performance guidelines for this and associated equipment. This second edition also includes provisions on high flow Type D hot stabs.

The American Petroleum Institute (API) provides free online public access to view read only copies of its key industry standards, including a broad range of technical standards. All API standards that are safety-related and that are incorporated into Federal regulations are available to the public for free viewing online in the Incorporation by Reference Reading Room on API's website at: *http://publications.api.org* [1]. In addition to the free online availability of these standards for viewing on API's website, hardcopies and printable versions are available for purchase from API. The API website address to purchase standards is: *https://www.api.org/products-and-services/standards/purchase.*

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

For the convenience of the viewing public who may not wish to purchase or view the incorporated documents online, the documents may be inspected at BSEE's offices at: 3801 Centerpoint Dr, Anchorage, Alaska, 99503 (phone: 907–334–5300); 1919 Smith Street, Suite 14042, Houston, Texas 77002 (phone: 1–844–259–4779); or 45600 Woodland Road, Sterling, Virginia 20166 (email: *regs@bsee.gov*), by appointment only. BSEE will make documents incorporated in the rule available for viewing at the time and date agreed upon for the appointment. Additional information on where these documents can be inspected or purchased can be found at 30 CFR 250.198, *Documents incorporated by reference,* or by sending a request by email to *regs@bsee.gov.*

Subpart C—Pollution Prevention and Control

Pollution prevention. (§ 250.300)

BSEE proposes to revise paragraphs (b)(1) and (2) of § 250.300 by eliminating the existing language that states the Regional Supervisor may require the capture of all water-based mud, and associated cuttings, from operations after completion of the hole for the conductor casing to prevent its discharge into the marine environment. While this proposed rule would eliminate the language regarding the Regional Supervisor's discretionary authority to require the capture of water-based muds and cuttings, it would maintain the existing requirement in § 250.300(b)(1) and (2) that operators capture all petroleum-based mud and associated cuttings while operating on the Arctic OCS.

Existing § 250.300(b)(1) and (2) state that the BSEE Regional Supervisor may exercise his or her discretionary authority to restrict discharges of water-based muds and associated cuttings from Arctic OCS exploratory drilling based on various factors, such as: Proximity of drilling operations to subsistence hunting and fishing locations; the extent to which discharged water-based mud or cuttings may cause marine mammals to alter their migratory patterns in a manner that impedes subsistence users' access to or use of those resources, or increases the risk of injury to subsistence users; or the extent to which discharged mud or cuttings may adversely affect marine mammals, fish, or their habitat. BSEE promulgated the existing provisions in response to concerns raised by Alaska Native Tribes during preparation of the 2015 Arctic Proposed Rule. These concerns included how water-based muds or cuttings could adversely affect marine species (*e.g.,* whales and fish) and their habitats and compromise the effectiveness of subsistence hunting activities.

BSEE re-examined the language in paragraphs (b)(1) and (2) of this section in light of EPA's authority to address water-based muds and cuttings discharges. The Clean Water Act (CWA) (Section 301(a), 33 U.S.C. 1311(a)) provides EPA with the authority to issue National Pollutant Discharge Elimination System (NPDES) general permits, which authorize certain discharges, including certain restricted discharges of water-based muds and cuttings, from oil and gas exploratory facilities on the OCS in the Beaufort Sea and the Chukchi Sea. Those general permits additionally prohibit the discharge of oil-based and non-aqueous based muds and cuttings. The EPA must issue an NPDES general permit before an operator may seek coverage under that general permit. Compliance with the CWA, including gaining coverage under an applicable NPDES general permit, is necessary before an operator may discharge pollutants from its exploratory drilling operations.

Before issuing an NPDES permit, EPA must make specific determinations to ensure that issuance of a permit will not lead to unreasonable degradation of the marine environment. EPA's determination is guided by an Ocean Discharge Criteria Evaluation (ODCE). The ODCE requires the agency to consider multiple environmental factors, such as potential impacts on human health through direct and indirect pathways, and the importance of the receiving water area to the surrounding biological community. These factors take into consideration how discharges could impact subsistence activities, marine resources, and coastal areas. The most relevant NPDES permits issued for offshore oil and gas exploration activities conducted from a MODU on the Arctic OCS are two 2012 general permits that covered oil and gas exploration facilities conducting operations in Federal waters of the Beaufort Sea and the Chukchi Sea. The Beaufort Sea permit [41] does not allow the discharge of water-based muds and cuttings during the fall bowhead whale hunt. However, the Chukchi Sea permit [42] did not include a similar restriction. According to the ODCE for the Chukchi Sea permit, the restriction was not necessary because the migration of bowhead whales would be over before discharge-related activities would begin.[43]

Under this proposed rule, BSEE would preserve the requirements in § 250.300(b)(1) and (2) that the operator capture all petroleum-based mud and associated cuttings. This requirement is consistent with a longstanding, OCS-wide regulatory authority that existed prior to the promulgation of the 2016 Arctic Exploratory Drilling Rule. BSEE must preserve the petroleum-based muds and cuttings requirement since it is not unusual for petroleum-based

[41] *https://www.epa.gov/sites/production/files/2017-12/documents/r10-npdes-beaufort-oil-gas-gp-akg282100-final-permit-2012.pdf.*

[42] *https://www.epa.gov/sites/production/files/2017-12/documents/r10-npdes-chukchi-oil-gas-gp-akg288100-final-permit-2012.pdf.*

[43] *https://www.epa.gov/sites/production/files/2017-12/documents/r10-npdes-chukchi-oil-gas-gp-akg288100-odce-2012.pdf,* pp. 6–14 to 6–17.

muds to contain constituents that are toxic and harmful to the environment. Although water-based muds may not be a feasible option for all drilling operations, such as when drilling through hydrophobic geologic formations that could be damaged by water-based muds, its use is a more environmentally benign approach in comparison to the use of petroleum-based muds. However, BSEE's proposed revisions reflect the Bureau's understanding that the express statements regarding the Regional Supervisor's discretionary authority to require the capture of water-based muds and cuttings in existing § 250.300(b)(1) and (2) are not necessary. In particular, the EPA already addresses the goals of protecting water quality through the NPDES program, protecting marine species and their habitats, as well as the effectiveness of subsistence hunting activities, through the exercise of that agency's authorities. Thus, BSEE does not expect the Regional Supervisor to need to exercise the discretionary authority under existing § 250.300(b)(1) and (2) in the foreseeable future.

Furthermore, BSEE understands, and did so even while it was preparing the 2016 Arctic Exploratory Drilling rule, that the references to the BSEE Regional Supervisor's authority in existing paragraphs (b)(1) and (2) created some uncertainty for the regulated industry because it appeared to overlap with EPA's jurisdiction and, if implemented, might result in BSEE issuing duplicative or conflicting requirements. BSEE addressed this concern by explaining that the amendments were meant to clarify the Regional Supervisor's authority to impose operational measures that complement EPA's discharge limitations by considering potential impacts to specific components of the Arctic environment, such as subsistence activities, marine resources, and coastal areas (81 FR 46505). Given the policy in E.O. 13783 to review existing regulations that potentially burden the development or use of domestically produced energy resources and the general principles in Section 1 of E.O. 13563—*Improving Regulation and Regulatory Review* (76 FR 3821)—to promote predictability and reduce uncertainty, BSEE believes it is appropriate to propose eliminating the water-based mud, and associated cuttings, provisions in § 250.300(b)(1) and (2).

This proposed regulatory change does not suggest any change in BSEE's recognition that it is responsible for ensuring that oil and gas exploration and production activities on the OCS are conducted in a safe and environmentally responsible manner pursuant to OCSLA. Therefore, the proposed rule would not alter the longstanding regulation at § 250.300(b)(1), under which the District Manager (or Regional Supervisor) retains the ability to restrict the rate of drilling fluid discharges or prescribe alternative discharge methods where warranted. Pursuant to § 250.300(b)(1), BSEE would be able to determine whether there is a need to require capture of water-based muds and cuttings on a case-by-case basis, if the EPA has not done so. In particular, the District Manager would consider and determine whether such a requirement would be appropriate for any facility. The District Manager would make this determination on a case-by-case basis, in conjunction with the EP and APD approval process. This process includes coordinating with BOEM, particularly at the EP stage, when BOEM conducts an environmental review to identify the direct, indirect, and cumulative environmental effects that may be expected as a result of implementing the EP. That environmental review also incorporates input about potential environmental effects that may be obtained through consultations and review by interested parties, Federal agencies (*e.g.,* EPA), State or local agencies, Tribes, or the public. Nothing would change BSEE's position from the 2016 rule to communicate with other agencies responsible for oversight of discharges related to oil and gas exploration drilling in the Arctic. This communication will help ensure that conflicts do not arise (81 FR 46504). BSEE expects that such input from EPA would address whether that agency has issued or plans to issue a permit for the same exploratory drilling facilities, and whether that agency believes that capture of water-based muds in a specific case is warranted. Through BSEE's longstanding authority under § 250.300(b)(1), the District Manager could require an operator to restrict the rate of drilling fluid discharges or prescribe alternative discharge methods. Such a restriction on the discharge of water-based muds and cuttings might be appropriate if identified in the EP environmental review process.

In addition to the proposed revisions just described, BSEE proposes a minor modification to the second sentence in existing paragraph (b)(2), which requires the operator to capture all cuttings from operations that ''utilize'' petroleum-based mud to prevent their discharge into the marine environment. BSEE proposes to replace the word ''utilize'' with ''use'' to improve the readability of the regulation.

Subpart D—Oil and Gas Drilling Operations

What additional information must I submit with my APD for Arctic OCS exploratory drilling operations? (§ 250.470)

BSEE proposes to revise paragraph (b) of § 250.470 by adding paragraph (b)(13) to include ''Recover the subsea isolation device (SSID), where applicable.'' This revision is necessary to address the SSID alternative proposed in § 250.472, and to ensure the operator's permit addresses how it would recover the SSID, if one is used. For operations relying on an SSID, the SSID is a critical piece of equipment. Therefore, BSEE must understand how the operators will handle it, prior to and after drilling operations. We also propose minor, non-substantive edits to paragraphs (b)(11) and (12) to accommodate this addition.

In cases where an operator obtains SCCE capabilities through contracting, paragraph (f)(3) currently requires the operator to provide proof of contracts or membership agreements with cooperatives, service providers, or other contractors. This includes information demonstrating the availability of the personnel and/or equipment on a 24-hour per day basis during operations below the surface casing. BSEE proposes to revise paragraph (f)(3) by replacing the ''below the surface casing'' language in this paragraph with the phrase ''below the surface casing, or before the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities, as approved by the Regional Supervisor.'' This change would make the requirement in paragraph (f)(3) consistent with the changes BSEE is proposing to § 250.471, which houses the substance of the Arctic OCS SCCE requirements. This proposed change is discussed in further detail in connection with that provision.

Finally, BSEE proposes to add a new paragraph (h) to complement the proposed revisions to § 250.472, which would provide the operator with the option to use an SSID or have access to a relief rig, as an additional means to secure the well in the event of a loss of well control, if the operator will be conducting exploratory drilling operations from a MODU (that change is discussed in further detail in connection with that provision). Under proposed paragraph (h), if the operator elects to use an SSID, BSEE would require the operator to provide a certification, signed by a registered professional engineer, confirming that its SSID and well design (including casing and cementing program) meet the design requirements in proposed § 250.472(a), and the design is appropriate for the purpose for which it is intended under expected wellbore conditions. BSEE is proposing this new provision to be consistent with existing requirements under existing § 250.420 (a)(7)(i), which require the operator to include with the APD a certification signed by a registered professional engineer that the casing and cementing design is appropriate for the purpose for which it is intended under expected wellbore conditions.

What are the requirements for Arctic OCS source control and containment? (§ 250.471)

Section 250.471(a) currently requires the operator to have access to the SCCE described in paragraphs (a)(1) through (3), which must be capable of stopping or capturing the flow of an out-of-control well if the operator will be using a MODU when drilling below or working below the surface casing. Paragraph (a)(1) specifically requires the capping stack to be positioned to ensure that it will be able to arrive at the well location within 24 hours after a loss of well control. Paragraphs (a)(2) and (3) require the cap and flow system and the containment dome to be positioned to ensure that they will be able to arrive at the well location within 7 days after a loss of well control.

BSEE proposes to revise § 250.471 by:

(i) Adding a new provision at the end of paragraph (a) stating that ''However, the Regional Supervisor will approve delaying access to your SCCE until your operations have reached the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities provided that you submit adequate documentation (such as, but not limited to, risk modeling data, off-set well data, analog data, seismic data), with your APD, demonstrating that you will not encounter any abnormally high-pressured zones or other geologic hazards. The Regional Supervisor will base the determination on any documentation you provide as well as any other available data and information.''

(ii) modifying the language in paragraph (a) describing the performance standard that the SCCE must meet by replacing ''capable of *stopping* or *capturing* the flow *of* an out-of-control well'' with ''capable of *controlling* or *containing* the flow *from* an out-of-control well when drilling below or working below the surface casing;'' and

(iii) removing the phrase ''positioned to ensure that it will arrive at the well location within 7 days after a loss of well control'' from subparagraphs (a)(2) and (3), which apply to the cap and flow system and containment dome, respectively.

The changes described in item (i) from the previous paragraph could allow the operator to adjust the point in time during operations when it must position its capping stack—from ''when drilling or working below the surface casing'' to ''when drilling or working below the last casing point prior to the zone capable of flowing hydrocarbons in measurable quantities''—if the operator is able to demonstrate that it will not encounter any abnormally high-pressured zones or other geological hazards before that casing point. However, unless otherwise approved by BSEE, the operator must have access to their SCCE as described in paragraph (a)(1) and proposed paragraphs (a)(2) and (3), when drilling or working below the surface casing. While BSEE does not propose changes to the capping stack provision in paragraph (a)(1), changes to paragraph (a) would have a practical effect on the existing capping stack requirements. Changes to the capping stack requirements are discussed in the next subsection, entitled, *Revisions to the Capping Stack Requirements.*

BSEE's proposed modifications to the language in paragraph (a), describing the performance standard that the operator's SCCE must meet, is administrative in nature. BSEE proposes this change so that the language is consistent with the source ''control'' and ''containment'' description of this equipment, as well as the title of this section of the regulations (*i.e.,* § 250.471 *What are the requirements for Arctic OCS source control and containment?*). It would not change the performance standard that the operator's SCCE must meet.

BSEE's proposed changes to remove the phrase ''positioned to ensure that it will arrive at the well location within 7 days after a loss of well control'' from paragraphs (a)(2) and (3) would still require the operator to ensure it has access to a cap and flow system or a containment dome. However, the operator would no longer be required to ensure the equipment is positioned to be able to arrive at the well location within 7 days after the loss of well control. The distinction between the positioning requirement and the requirement to have access to the equipment is that ''having access'' refers to ensuring the operator has identified the equipment that would meet the performance requirements in this section and in other existing BSEE regulations—§ 250.462 (*What are the source control, containment, and collocated equipment requirements?*) and is able to deploy the equipment as directed by the Regional Supervisor. Details regarding BSEE's proposed revisions to § 250.471(a)(2) and (3) are discussed in the subsection below, entitled, *Revisions to the Cap and Flow System, and Containment Dome Requirements.*

- *Revisions to the Capping Stack Requirements*

BSEE's proposed revisions to paragraph (a) would provide an opportunity to the operator to adjust the point in time during operations when it must position its capping stack, so that it will be available to arrive at the well location within 24 hours after a loss of well control. If the operator is able to demonstrate to BSEE that the operations it plans to conduct below the surface casing would not encounter any abnormally high-pressured zones or other geologic hazards before reaching the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities, then BSEE would allow the operator delay its positioning of the capping stack until that point. A capping stack, as defined under the existing regulations at § 250.105, is a mechanical device that can be installed on top of a subsea or surface well head or BOP to stop the uncontrolled flow of fluids into the environment. BSEE also proposes certain non-substantive language changes for clarity.

The existing capping stack requirements in paragraphs (a) and (a)(1) are intended to ensure that a capping stack is readily available to stop or capture the flow of hydrocarbons in case of a loss of well control when drilling below or working below the surface casing. While BSEE does not propose to eliminate the requirement in paragraph (a)(1) to ensure that the capping stack will be able to arrive at the well location within 24 hours after a loss of well control, the existing requirement in paragraph (a) to ensure the equipment is accessible when drilling below the surface casing does not fully take into consideration the known geology of an area. The formations below the surface casing, based on the known geology of the area, may have minimal or no potential to flow hydrocarbons in measurable quantities during drilling operations. This obviates the need for ensuring capping stack availability during operations in those zones. Prior to submitting an APD, operators assess the formations they will potentially encounter during drilling operations, including the potential for hydrocarbon flow. Operators base this assessment on existing G&G data that they include in the APD.

In many cases, flowable hydrocarbons are not anticipated or encountered in measurable quantities until the target productive formation is reached. For example, a surface casing shoe setting depth for an Arctic OCS exploration well could be only 1,500 feet, but the hydrocarbon bearing formation may be thousands of feet below that point. The existing regulations require the operator to have access to an available capping stack when drilling or working below the surface casing, even though geologic and engineering risk analyses the operator must submit as part of their APD may show that there is little or no potential for hydrocarbons to escape the formation and flow into the well prior to reaching the targeted productive formation. In such circumstances, the operator could safely drill for thousands of feet below the surface casing, without any identifiable need for a capping stack. This proposed change would, when appropriate, eliminate an unnecessary burden for the operator to maintain a positioned capping stack while drilling into low risk, non-productive sections of the well below the surface casing.

An extensive amount of geophysical data already exists for certain areas of both the Beaufort and Chukchi Sea Planning Areas, and there has been extensive drilling in certain areas of the Beaufort Sea Planning Area. In the known geologic conditions of the U.S. Arctic, operators have a good understanding of the locations of reservoirs that they will encounter, which can be relatively shallow and normally pressured above certain geologic depths. Therefore, it may not be necessary to have access to a capping stack when drilling through zones below the surface casing that do not have abnormally high formation pressures or contain other geological hazards, and do not have the potential to flow hydrocarbons in measurable quantities, as they are penetrated.

However, because geologic conditions are not uniformly normally pressured throughout the Arctic OCS, BSEE is maintaining the existing requirement to have the capping stack positioned when drilling or working below the surface casing. At the same time, BSEE does not discount the possibility that future projects would not need to have SCCE (*i.e.,* the capping stack) positioned until reaching the last casing point prior to penetrating a zone capable of flowing hydrocarbons.

The criteria BSEE proposes to rely on—that the operator can demonstrate to BSEE that it will not encounter ''abnormally high-pressured zones or other geologic hazards''—to determine whether to grant an exception accounts for those downhole risks that could lead to a blowout and may require the use of a capping stack. With respect to abnormally high-pressured zones, BSEE is concerned that there could be a case where a kick (an influx, or flow, of formation fluid from the high-pressured zone entering into the wellbore) is not controlled and could lead to a blowout. While there are means of mitigating the risk of a kick, (*i.e.,* overbalanced drilling), the capping stack needs to be readily available if heavier weight drilling muds, the BOP, and SSID, if applicable, fail to control the well.

There could be other geologic hazards, such as fractured or high permeability zones, that may also pose a risk, particularly if those zones contain hydrocarbons. It is possible that normally pressured zones may be highly permeable or contain fractures, in which lost circulation may occur. This could cause a dynamic effect where drilling mud flows into the permeable formation causing the circulating pressure to decrease below the zone's pore pressure resulting in formation fluids flowing into the well bore. This may lead to a loss of well control. The capping stack needs to be readily available if heavier weight drilling muds, the BOP, and SSID, if applicable, fail to control the well.

However, if the operator is able to demonstrate that a highly permeable or fractured zone is predicted to only contain water, BSEE would consider allowing the operator to delay positioning of the capping stack. Under this scenario, the operator would be able to use the diverter system in conjunction with the BOP system to maintain safety and environmental protection because it would be unlikely for hydrocarbons to be released into the environment. The diverter system consists of a mechanical device similar to a BOP annular preventer. The diverter system is used to divert gases, fluids, and other materials flowing from the well, away from facilities and personnel. Also, an operator would pump fluid loss materials into the well to bridge the formation to reduce its permeability and allow drilling muds to isolate the formation from the well. To permanently address the incident, the operator could also install a liner or set a new casing point at the interval where that highly permeable or fractured zone is located. BSEE would like to know whether there are more appropriate criteria, other than ''abnormally high-pressured zones or other geologic hazards,'' that the Bureau should use to determine whether to allow the operator to delay positioning of the capping stack.

BSEE's proposed regulatory language describing the types of documentation it would consider adequate to demonstrate that abnormally high-pressured zones or other geological hazards would not be encountered before reaching the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities—''such as, but not limited to, risk modeling data, off-set well data, analog data, seismic data''—is not meant to be an exhaustive list. BSEE would accept any other types of documentation the operator may provide that will help its demonstration. BSEE does not anticipate this submission requirement would lead to a significant information collection burden on the operator because it is normal practice for operators to gather these types of information to develop and design an offshore exploration drilling project on the OCS in the Arctic. BSEE is requesting comment on what other types of information could be used to demonstrate the absence of abnormally pressured zones or other geologic hazards, and how burden on the operator could change—increase or decrease—if BSEE were to require its submission.

At the APD stage, BSEE would evaluate the operator's documentation along with other accompanying geologic and engineering information/analyses that must be submitted as part of its APD. BSEE would also consider any other available G&G information, such as information gathered from prior drilling operations in the area (*e.g.,* well log and pressure testing information), and any other applicable geophysical (*e.g.,* seismic data) information. BSEE makes clear in its proposed regulatory language that the Regional Supervisor will base the determination on whether to allow the operator to delay positioning of the capping stack on the documentation that the operator submits, as well as any other available data and information.

BSEE is also considering an alternative regulatory approach whereby the Bureau would instead revise existing paragraph (a) by replacing ''surface casing'' with ''last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities.'' This regulatory option would uniformly adjust the point in time during operations when the operator must have access to its capping stack, by requiring the operator to have its capping stack positioned before drilling below or working below the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities.

Under this regulatory option, BSEE would evaluate the geologic and engineering information/analysis that the operator must submit as part of its APD, while also taking into consideration any other available G&G information the Bureau may have (*e.g.,* off-set well data, such as well logs and pressure testing information, or geophysical information, such as seismic data). Based on these different sources of information, BSEE would determine whether there may be a need for the operator to position the capping stack at a point in time during operations earlier than last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities.

There may be cases where the operator or BSEE may not have sufficient G&G or analogous well data during the permit review process on a proposed project to provide an adequate level of certainty regarding anticipated formations that may be encountered prior to reaching the targeted productive formation. Therefore, BSEE is also considering, as part of this regulatory option, a clarification that the Regional Supervisor may require the operator to have access to a capping stack in advance of drilling below or working below the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities if BSEE determines there is insufficient G&G or analogous well data.

For example, there may be insufficient G&G or analogous well data in cases where there have been a limited number of wells drilled within proximity to the planned well. In most cases, G&G and analogous well data are gathered from multiple sources. However, the same sets and amounts of data and information may not be available for each area, well, or project. There is no single set of criteria for determining the sufficiency of G&G or analogous well data. The more data that are available from sources near to the proposed drilling location, the greater confidence BSEE will have in the G&G interpretations. BSEE wants to ensure the operator has the most accurate data to make determinations about where the zones capable of flowing hydrocarbons in measurable quantities are located.

This alternative regulatory option would maintain the same level of safety and environmental protection in comparison to BSEE's proposed regulatory change. The decision on whether it is appropriate to delay positioning of the capping stack at a point in time when operations are taking place below the surface casing resides with BSEE. BSEE, ultimately, may decide not to allow the operator to delay positioning of the capping stack if the Bureau reasonably assesses that potential risks below the surface casing exist that may require immediate deployment of this device. However, the distinction under this regulatory option is that the operator would not need to specifically demonstrate that abnormally high-pressured zones or other geologic hazards would be encountered above last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities. The presumption would be that all zones above the last casing point prior to penetrating a zone capable of flowing hydrocarbons are safe unless BSEE determines otherwise. In addition, under BSEE's proposed regulatory change, it would be clear that the Bureau may request additional information from the operator and would provide that BSEE may consider other available data and information.

BSEE is specifically soliciting comments about the benefits or disadvantages of this regulatory option. BSEE is also soliciting comments about the need for the operator to verify on a case-by-case basis those zones incapable of flowing hydrocarbons in measurable quantities. Operators verify these zones by analyzing G&G data to evaluate the formations that are expected to be encountered during drilling operations and confirm that there are no hydrocarbons present. Operators must use available offset well data in conjunction with the G&G data. BSEE requests comment on other methods operators use to verify the hydrocarbon zones, or abnormally high-pressured zones or other geologic hazards (such as fractured or high permeability zones), they anticipate encountering for a proposed drilling project and how frequently the data would be lacking at the point of preparing information to submit as part of an APD.

• *Revisions to the Cap and Flow System, and Containment Dome Requirements*

As described at the beginning of this section-by-section discussion, § 250.471, BSEE is also proposing to revise paragraphs (a)(2) and (3) of existing § 250.471, which refers to the timing of the arrival of a cap and flow system and containment dome, respectively, by removing the phrase ''positioned to ensure that it will arrive at the well location within 7 days after a loss of well control'' from each paragraph. This proposed change would remove the requirement to have a cap and flow system or a containment dome positioned to ensure the equipment will be available to arrive at the well location within 7 days after the loss of well control, while preserving the existing requirement to deploy those pieces of equipment as directed by BSEE.

BSEE proposes to allow the operator to adjust the point in time during operations when it must position its capping stack under paragraph (a), from ''when drilling or working below the surface casing'' to ''when drilling below or working below last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities'' if the operator is able to demonstrate that it will not encounter any abnormally high-pressured zones or other geologic hazards before that casing point. Only the 7-day arrival timing related to the ''flow'' part of the cap and flow system would be altered as a result of BSEE's proposed modification to paragraph (a)(2) of § 250.471.[44]

The changes proposed in paragraphs (a)(2) and (3) to remove the requirement for the cap and flow system and the containment dome to arrive at the well location within 7 days after a loss of well control would not change other existing requirements throughout § 250.471 for the operator to ensure:

(i) Access to a containment dome and cap and flow system;

(ii) that the cap and flow system is designed to capture at least the amount of hydrocarbons equivalent to the calculated WCD rate referenced in the operator's BOEM-approved EP;

(iii) that the containment dome has the capacity to pump fluids without relying on buoyancy;

(iv) that tests or exercises are conducted for the SCCE, as directed by the Regional Supervisor;

(v) that records pertaining to the testing, inspection, maintenance, and use of the SCCE are maintained and made available to BSEE upon request;

(vi) that all SCCE identified in § 250.471 are transported to the well upon a loss of well control; and

(vii) that SCCE is deployed as directed by the Regional Supervisor.

BSEE proposes to remove the cap and flow system and containment dome 7-day arrival timing requirements based on the Bratslavsky and SolstenXP study. The Bratslavsky and SolstenXP study determined that the time periods when SCCE may be safely deployed throughout the Arctic OCS is limited based on typical Arctic conditions. In

[44] Existing § 250.105 defines Cap and flow system and Capping stack.

the Chukchi Sea, this means that safe SCCE deployment could only occur between August and October in the historically active exploration area. Moving north from the historically active exploration area of the Chukchi Sea, the ability to safely deploy SCCE diminishes significantly (*id.* at 100). The study mentions there are more opportunities for safe deployment of SCCE in other portions of the Chukchi Sea (June through December). However, it is only in the southwestern extent of the Chukchi Sea Planning Area; outside of the historically active exploration area.

In the Beaufort Sea, the study noted that sea ice concentrations tend to be greater year-round as compared to the Chukchi Sea (*id.* at 75). Accordingly, safe SCCE deployment could occur from ice capable vessels between early August and October in the historically active exploration area of the Beaufort Sea (*i.e.,* the southern portion of the Beaufort Sea Planning Area). However, moving north beyond the historically active exploration area, time windows for safe SCCE deployment decrease significantly (*id.* at 104).

In the case of open water operations in both the Chukchi and Beaufort Seas, the study points out that sea state is an important limiting factor for safe SCCE deployment. Rough sea states—high waves and longer wave periods—can affect the safety and operating limits of SCCE deployment. The vessel carrying the SCCE can become very unstable in rough sea states and the heave action on the deck can therefore increase significantly beyond the vessel's tolerance levels for conducting operations, which may negatively affect the ability to safely deploy the SCCE. Rough sea states are most likely to occur when there is less sea ice coverage and larger open water areas to generate large waves, which is more of an issue in the Chukchi Sea, where there are larger open water areas throughout the open water season (*id.* at 11).

When operating in open water conditions, sea states generally dictate that safe SCCE deployment could occur only between late September and October in the historically active exploration area of the Chukchi Sea, and that window diminishes significantly moving north of the historically active exploration area. In the Beaufort Sea, where there is less open water throughout the operating season, sea states would generally permit safe deployment of SCCE between late-August and early-to mid-October in the historically active exploration area. Beyond that, the probability for safe SCCE deployment decreases rapidly in the historically active exploration area and in the other areas of the Beaufort Sea. (*id.* at 98,102)

Water depth is also an important factor to consider for the safe deployment of SCCE. Deployment is likely to be impaired in water depths shallower than 984 feet because the equipment would potentially be subject to a gas boil at the surface from a subsea blowing well (*id.* at 143). A gas boil is a forceful release of hazardous gases which can present human-health hazards to workers, fire hazards, and potential stability problems for support vessels and the vessel deploying the SCCE directly above the blowing well. Water depths in the majority of the Chukchi Sea and Beaufort Sea where exploration has historically occurred are relatively shallow—167 feet or less (Table 1–1 and Table 1–2, *id.* at 7 to 9). As recently as April of 2020,[45] there were active leases in the Arctic OCS where SCCE may be deployed. These leases were located in the Beaufort Sea in water depths less than approximately 170 feet deep. This water depth range limits the fleet of support vessels that can be used for the safe deployment of SCCE. A possible solution that could enable SCCE deployment in the presence of a gas boil is the use of offset-deployment technology to remotely position SCCE over the blowing well in shallow water (*id.* at A–35).

When BSEE proposed its original Arctic OCS SCCE requirements in 2015, the Bureau explained that there is limited ability in the Arctic region to summon additional source control and containment resources. Accordingly, the Bureau required operators to plan for response redundancies and planning complexities not required elsewhere (80 FR 9938). BSEE determined that the provisions finalized in 2016 provided for the necessary redundancy and sequencing of the responses, based on the time necessary to deploy, and therefore provided sufficient safety and environmental protection to allow for exploratory drilling on the Arctic OCS. At that time, BSEE believed that the technologies identified in its SCCE requirements represented the optimal approach to well control capabilities available for the Arctic OCS (81 FR 46520).

[45] In April of 2020, the only leases with potential projects that would be subject to the Arctic OCS's SCCE requirements were relinquished. However, there are other active leases in the Beaufort Sea located nearer to the shore in shallow waters where exploration and development projects are being pursued (primarily through man-made gravel islands).

Since publication of the 2016 rule, however, BSEE has sought to better understand the ability to safely deploy SCCE (and relief rigs) in Arctic OCS conditions, through a study it commissioned to Bratslavsky Consulting Engineers, Inc., and SolstenXP, Inc. According to the Bratslavsky and SolstenXP study, the time periods when SCCE may be safely deployed throughout the Arctic OCS is limited in comparison to relief-well drilling operations, based on typical Arctic conditions. BSEE did not have the benefit of having the Bratslavsky and SolstenXP study when finalizing the 2016 Arctic Exploratory Drilling Rule. BSEE's proposed changes to § 250.471(a)(2) and (3) for the containment dome and cap and flow system responds to the information it has gathered from the study.

In light of these findings, BSEE proposes the revisions under § 250.471 to the containment dome and cap and flow system deployment requirements in paragraphs (a)(2) and (3) because it is not reasonable to impose such universal, prescriptive requirements for equipment that may not be safely deployed (moved to the location, equipment put into place, and activated) and effectively used under certain Arctic OCS conditions. The deployment and arrival schedules of the cap and flow system and the containment dome will be directed by the BSEE Regional Supervisor on a case-by-case basis.

However, as previously described, BSEE proposes only to adjust, rather than eliminate, the reference to the point in time during operations when the operator must have access to a capping stack that is positioned to be able to arrive at the well location within 24 hours after a loss of well control. The Bratslavsky and SolstenXP study shows that the time periods when SCCE (capping stack, containment dome, and cap and flow system) may safely be deployed and effectively used are limited. Metocean conditions (*i.e.,* rough sea states and sea ice concentrations) prevalent in the Arctic OCS can exceed the operating limits of the vessels that transport and deploy the SCCE. In addition, SCCE deployment is likely impaired in water depths shallower that 984 feet, where gas boils could form above a blowing well. Water depths in the majority of the Chukchi Sea and Beaufort Sea where exploration has historically occurred are relatively shallow—167 feet or less. However, BSEE's independent observation outside of the study is that the chances for successfully deploying a capping stack under Arctic OCS conditions is greater in comparison to the containment dome and cap and flow system. More specifically, in comparison to the containment dome, the capping stack has proven to be a more effective technology when successfully deployed and has a different function compared to a containment dome. The capping stack latches on to a connector or pipe stub located on or in the well to achieve a pressure tight seal to capture or stop all fluids flowing out of the well. A containment dome, which removes oil and gas from the water column, will likely capture only a portion of the hydrocarbon flow due to the non-sealing design. In addition, the use of a containment dome may be constrained by the drilling unit itself. Certain drilling rigs, such as jackups and submersible drilling vessels, are unlikely to provide adequate structural clearance for deployment of a containment dome without moving the rig off the drill site. (*id.* at 33). Furthermore, containment domes have limited field application to prove their capabilities while, in contrast, capping stacks have been field tested and successfully deployed in multiple practice drills (*id.* at 32 and 34).[46]

With respect to the cap and flow system, the flow portion of the system would require additional vessel support activities on the surface (*e.g.,* support vessels for oil and gas processing, and hydrocarbon storage/transfer) to keep the system working in comparison to what would be needed to deploy a capping stack (*e.g.,* a single vessel that would load the capping stack and deploy to the well when needed). The support activities and the vessel on which the flow system is loaded would be subject to the same challenging metocean conditions previously described, thus limiting their ability to be safely deployed throughout the Arctic drilling season. The capping stack would generally have a better opportunity for deployment because once the capping stack is lowered under the water and attached to the wellhead, weather becomes less of a factor.

BSEE believes it is critical to ensure that operators have redundant protective measures in place, as there is no guarantee that a single measure could control or contain a worst-case discharge (*see* 81 FR 46487). Because the chances of successfully deploying a capping stack under Arctic OCS conditions may be greater in comparison to the containment dome and cap and flow system, BSEE is revising, and not eliminating, the capping stack positioning requirement. BSEE invites comments on any technological upgrades or methods that exist for SCCE that would meet the objective of being a redundant system that could control or contain a WCD.

Although BSEE is proposing to remove the requirement in existing paragraphs (a)(2) and (3) to ensure that the cap and flow system and containment dome will be available to arrive at the well location within 7 days after a loss of well control, BSEE would maintain the provisions under the same paragraphs that require that the operator identify and have access to a containment dome and cap and flow system capable of deployment as directed by BSEE. BSEE would also maintain the requirement under existing paragraph (g) to initiate transit of all SCCE identified under § 250.471 upon a loss of well control. Collectively, the proposed revisions to paragraphs (a)(2), (a)(3), and existing paragraph (g) would mean that, in the event of a loss of well control, the containment dome and cap and flow system would be in transit while the capping stack is being deployed at the well location. In light of the distinct functions and capabilities of these various elements of SCCE under anticipated Arctic OCS exploratory drilling conditions, BSEE proposes to retain these requirements, as modified, to preserve the regulations' requirement for redundant protective measures, while acknowledging the capability of each SCCE component, as there is no guarantee that a single measure could control or contain a WCD.

Finally, BSEE proposes to revise existing paragraph (b) by eliminating the requirement for the operator to conduct a stump test of a pre-positioned capping stack, if the operator elects to use one, prior to installation on each well. This proposed change would provide consistency with BSEE's proposed revision to the definition of a capping stack in § 250.105 and the new SSID alternative BSEE is proposing under § 250.472. BSEE's proposed SSID alternative includes specific testing procedures, which is discussed in detail later in this preamble. BSEE's prior references to ''pre-positioned capping stacks'' were intended to address a comment on the 2015 Arctic Exploratory Drilling Proposed Rule suggesting that the definition of a capping stack be expanded to allow pre-positioned capping stacks to be used below subsea BOPs when deemed technically and operationally appropriate.

What are the additional well control equipment or relief rig requirements for the Arctic OCS? (§ 250.472)

Paragraph (b) of § 250.472 currently requires the operator to have access to a relief rig (different from the primary drilling rig), when drilling or working below the surface casing. In addition, when drilling or working below the surface casing, paragraph (b) requires the operator to stage the relief rig so that it could arrive on site, drill a relief well, kill and permanently plug the out-of-control well, and abandon the relief well prior to expected seasonal ice encroachment at the drill site, and in no event later than 45 days after the loss of well control.

BSEE proposes to revise the existing relief rig and SSRW requirements in § 250.472 by:

(i) Providing the operator with an option to either use an SSID or have access to a relief rig, if the operator will conduct exploratory drilling operations from a MODU;

(ii) Establishing the requirements that the operator must satisfy if the operator elects to use an SSID to comply with § 250.472;

(iii) Establishing the requirements that the operator must satisfy if the operator elects to have access to a relief rig to comply with § 250.472;

(iv) Adding a new provision that would apply if the operator elects to have access to a relief rig, which states, ''However, the Regional Supervisor will approve delaying access to your relief rig until your operations have reached the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities provided that you submit adequate documentation (such as, but not limited to, risk modeling data, off-set well data, analog data, seismic data), with your APD, demonstrating that you will not encounter any abnormally high-pressured zones or other geological hazards. The Regional Supervisor will base the determination on any documentation you provide as well as any other available data and information.''; and

(v) Eliminating the reference to expected seasonal ice encroachment at the drill site, which applies to relief rig operations.

With respect to the structure of § 250.472, proposed paragraph (a) would establish the requirements the operator must follow if the operator elects to use an SSID, and proposed paragraph (b) would establish the requirements the operator must follow if the operator elects to maintain access to a relief rig. BSEE would combine the

[46] For example, the capping stack technology was used to shut-in the *Macondo* well during the Deepwater Horizon incident.

requirements in existing paragraphs (a) and (b) into a single paragraph—proposed paragraph (b)—for organizational purposes, since existing paragraphs (a) and (b) cover relief rigs. Proposed paragraph (b) would also include the relief rig-related revision described in item *(iv)* of the previous paragraph, which could allow the operator to adjust the point in time during operations when it must stage its relief rig—from ''when drilling or working below the surface casing'' to ''when drilling or working below the last casing point prior to the zone capable of flowing hydrocarbons in measurable quantities''—if the operator is able to demonstrate that it will not encounter any abnormally high-pressured zones or other geological hazards before that casing point. However, unless otherwise approved by BSEE, the operator must stage its relief rig in a location, such that the relief rig would be available to arrive on site, drill a relief well, kill and abandon the original well, and abandon the relief well no later than 45 days after the loss of well control, when drilling or working below the surface casing. Finally, proposed paragraph (b) would include the proposed relief rig-related revision to eliminate the reference to expected seasonal ice encroachment at the drill site, which could potentially extend the open-water drilling season for MODUs. The changes included in proposed paragraphs (a) and (b) are discussed in further detail below, respectively, under the two subheadings entitled, *Proposed Paragraph (a)—Complying with § 250.472 by Using an SSID* and *Proposed Paragraph (b)—Complying with § 250.472 by Having Access to a Relief Rig.*

In addition, the general alternative compliance language in existing paragraph (c) would be eliminated because the proposed rule would provide the operator with the alternatives of either using an SSID or having access to a relief rig, and because § 250.141, *May I ever use alternate procedures or equipment?,* already provides an option for an operator to seek approval to use alternate procedures or equipment, potentially including future technologies that have not yet been developed.

When it promulgated the 2016 Arctic Exploratory Drilling Rule, BSEE understood that, based on past loss of well control events (including the *Deepwater Horizon* incident), it was important for the operator to be prepared to drill a relief well to permanently plug a well, in the event of a loss of well control. Arctic OCS exploratory drilling operations conducted from MODUs are complicated by the fact that these operations can take place only during a short period each year, when ice hazards can be physically managed and there is no continuous ice layer over the water. Outside of that window, ice encroachment complicates or prevents drilling, including drilling a relief well, and transit operations. Therefore, BSEE concluded in the proposed rule: Oil and Gas and Sulphur Operations on the OCS—Requirements for Exploratory Drilling on the Arctic OCS (February 24, 2015, 80 FR 9916) that, for Arctic OCS Conditions, it was necessary to establish a relief rig and SSRW requirements, whereby the rig would be positioned at a location that would enable it to transit to the well site, drill a relief well, kill and permanently plug the out-of-control well, plug the relief well, and demobilize from the site, prior to expected seasonal ice encroachment. (*see* 80 FR 9940).

Prior to finalizing the 2016 Arctic Exploratory Drilling Rule, BSEE did not identify any alternative technologies that provided a comparable level of results to drilling a relief well and permanently killing an out-of-control well. Drilling a relief well prior to seasonal ice encroachment eliminates the risk of a prolonged uncontrolled flow of hydrocarbons under the ice, throughout the winter season. The SCCE intervention options in BSEE's existing regulations (capping stack, cap and flow system, and containment dome) are intended only to temporarily control a well and not to be left in place over an entire ice season. However, BSEE did provide an option through the 2016 rule for the operator to request that BSEE approve ''alternative compliance measures to the relief rig requirement,'' as provided in the longstanding regulation at § 250.141, *May I ever use alternate procedures or equipment?*

Since the promulgation of the 2016 Arctic Exploratory Drilling Rule, BSEE has received and considered new information regarding the current relief rig and SSRW requirements in § 250.472. BSEE used the following information when developing the proposed requirements of this section:

• *Supplemental Assessment to the 2015 Report on Arctic Potential: Realizing the Promise of U.S. Arctic Oil and Gas Resources (NPC 2019 Report)*

In April 2018, the Secretary of Energy, in cooperation with DOI, requested that the NPC develop a supplemental assessment to the NPC 2015 Report. In April 2019, the NPC issued a report entitled, ''*Supplemental Assessment to the 2015 Report on Arctic Potential: Realizing the Promise of U.S. Arctic Oil and Gas Resources.*'' The supplemental assessment evaluated recent experiences with Arctic exploration and advancements in technology, and it provided findings and recommendations directed toward enhancing the Nation's regulatory environment to improve reliability, safety, efficiency, and environmental stewardship for Arctic oil and gas development. One of the key areas the Secretary of Energy requested that the NPC address was regulatory burdens related to development on the Arctic OCS. (NPC 2019 Report at A–1)

The NPC 2015 Report described various technologies employed by industry as preventative measures, to reduce the risk of a well control incident or to mitigate the impacts of an incident through response and recovery measures. It recommended further examination of source control and containment technologies, including capping stacks and SSIDs, noting that such alternatives ''. . . could prevent or significantly reduce the amount of spilled oil compared to a relief well, which could take a month or more to be effective.'' (NPC 2015 Report at 4–16).

In July/August of 2007, BSEE's predecessor, MMS, published a paper entitled, ''Absence of fatalities in blowouts encouraging in MMS study of OCS incidents 1992–2006.'' You may download and view the paper at *http://drillingcontractor.org/dcpi/dc-julyaug07/DC_July07_MMSBlowouts.pdf.* The paper summarizes BSEE's assessment of statistical information about loss of well control events that occurred during drilling operations on the OCS from 1992 through 2006. The paper noted that although relief wells were initiated in 2 of the 39 blowouts that occurred during the study period, both wells were controlled by other means prior to completion of the relief well. According to the NPC 2015 report, ''[a] relief well under good weather conditions may take 30 to 90 days plus rig mobilization, whereas a capping stack could be installed significantly sooner, and a subsea shut-in device could be activated in minutes.'' (NPC 2015 Report at 8–17)

The NPC 2019 Report noted that, when ExxonMobil drilled an exploratory well in the Russian waters of the Kara Sea, it used an SSID that was built and tested in Norway. According to the NPC 2019 Report, the SSID used in the Kara Sea used existing capping stack technology, including dual blind shear rams; an upgraded, redundant control system; and side inlets for intervention below the shear rams. (*id.* at C–10). At the same time, the NPC 2019 Report described the SSID as similar to a second BOP that was designed to be left on the wellhead, instead of being removed with the drilling rig, if the rig moves off the well near the end of the drilling season. The SSID, which could be actuated remotely, and the casing design together were capable of safe full well shut-in, diminishing the risk related to a loss of well control event occurring in late season and continuing over the winter season. The NPC 2019 Report observed that this design approach could eliminate the need for an SSRW. (*id.* at C–28). Ultimately, the NPC recommended that the use of an SSID, in conjunction with capping stacks, be accepted in place of the existing requirement for SSRW capability. (*id.* at 2).

The NPC 2019 Report also included additional data regarding the geologic characteristics of the formations targeted during exploratory drilling operations in the Chukchi Sea and Beaufort Sea. The NPC 2019 Report provides an illustrative comparison of the geologic depths encountered in the Arctic OCS and the Gulf of Mexico OCS. (NPC 2019 Report at 11). The shallower targeted geologic formations in the Arctic OCS make drilling less complex and lower risk. This is different from current water depths encountered by operators in the Gulf of Mexico. In the Arctic OCS, exploratory drilling operations conducted from MODUs have taken place in waters less than 200 feet. In the Gulf Mexico, drilling activities are continually taking place in waters deeper than 9,000 feet.

The Arctic OCS's distinct challenges are driven by the region's extreme environmental conditions, geographic remoteness, and a relative lack of fixed infrastructure and existing operations. In comparison to the Gulf of Mexico, the Arctic OCS lacks extensive operations and infrastructure from which resources could be drawn to respond to a well control incident. In addition, the open water season for drilling from a MODU is limited, allowing operators to perform drilling operations only during the summer and early fall. A late-season well-control event could challenge an operator's ability to perform well intervention operations prior to freeze up.

• *Suitability of Source Control and Containment Equipment versus SSRW in the Alaska Outer Continental Shelf Region (Bratslavsky and SolstenXP, 2018)*

In addition to the NPC 2019 Report, BSEE received information about SSIDs through the Bratslavsky and SolstenXP study, discussed in the previous section in connection with the proposed changes to the current Arctic OCS source control and containment requirements in § 250.471. As previously mentioned, the Bratslavsky and SolstenXP study entailed a comprehensive review and gap analysis of U.S. and international regulations, standards, recommended practices (RP), specifications, technical reports, and common industry methods regarding the safe deployment of SCCE as compared to the effectiveness of drilling an SSRW in Arctic conditions. BSEE notes that the Bratslavsky and SolstenXP study refers to the SSID as a ''subsea intervention device'' and considers the device to be SCCE, which is used to mitigate the consequences of a well control event. However, consistent with the findings in the NPC 2019 Report that categorizes SSIDs as preventative measures (instead of a response and recovery measure), BSEE considers SSIDs to be a barrier intended to prevent or minimize the impacts of a well control event. (*id.* at 16).

The Bratslavsky and SolstenXP study noted that an SSID was installed and field tested on a submersible drilling vessel (*i.e.,* a steel drilling caisson) for a 2005/2006 drilling project in the Canadian Beaufort Sea. However, the system was not completed in time to meet the approval process timelines and shipping deadlines required for timely implementation of the unit. (Bratslavsky & SolstenXP at A–36). According to the study, the use of a preinstalled SSID could provide a faster and safer additional line of defense for a response to a blowout than an SSRW or deployment of a capping stack or containment dome, resulting in smaller discharges to the environment. The report also mentions that the ability to remotely function the SSID ensures that it can be used in instances where other types of SCCE cannot be deployed due to site hazards that make it unsafe or inaccessible. These instances may include: A blowout with pressurized fluids coming up solely through the wellbore (forming a gas boil on the surface), a rig catching fire or collapsing on top of the well, or an incident in an area where response operations are limited, such as in shallow waters (*id.* at 35). The report also stated that if the well is designed to accommodate a full shut-in of the last casing string interval, the SSID can temporarily cap and control a well and facilitate its plugging and abandonment. This finding is consistent with the information from the NPC 2019 Report discussed previously. In 2008, Chevron initiated a technology venture with its partners on an R&D project to develop an SSID that would advance the best BOP technologies available at the time and would meet or exceed Canada's SSRW Arctic offshore regulations. The SSID was known as the Alternative Well Kill System (AWKS), which had two shear rams that were capable of simultaneously shearing and sealing heavier wall, larger diameter tubulars, and casings than was possible at that time. According to the NPC 2015 Report, Chevron successfully completed its testing of the AWKS in 2014 and is ready for deployment. (NPC 2015 Report at 4–18).

Although the Bratslavsky and SolstenXP study points out that SSIDs could provide a faster and safer response to a blowout than capping stacks or containment domes, BSEE does not conclude from this observation that SSIDs should also replace the SCCE requirements in existing and proposed § 250.471. In the Arctic, it is critical for the operator to have redundant protective measures in place, as there is no guarantee that a single measure could control or contain a WCD. (*see* 81 FR 46487). In addition to these redundant protective measures, the SSID, well design, and BOPs serve as controls and barriers that prevent or minimize the likelihood of loss of well control.

Other pertinent information from the Bratslavsky and SolstenXP study includes the statistical analysis of recent OCS drilling seasons in the Beaufort and Chukchi Seas. The analysis identified the metocean and operational conditions that would support the safe drilling of a relief well. The study noted that the hazards of sea ice to drilling vessels and associated support vessels are primarily determined by the concentration and thickness of the sea ice. A vessel's ice classification, which are determined by various marine classification societies, such as the American Bureau of Shipping (ABS) and Det Norske Veritas and Germanischer Lloyd (DNV GL), indicates the vessel's capabilities. As ice concentrations increase, a vessel's efficiency decreases. (Bratslavsky & SolstenXP at 23).

The study notes that the currently available open water operating season in the Chukchi Sea ranges from approximately 60 to 90 days in the historically active exploration area. (*id.* at 143). However, the results of the study showed that there is a high probability (90 percent) that drilling can be conducted safely in sea ice conditions in a majority of the historically active exploration area of the Chukchi Sea for 70 to 160 days if an ice class MODU and associated support vessels are used as part of the drilling operation. (*id.* at 108 and 145). Moreover, the NPC 2019 Report notes that ''vessels and equipment that are positioned in the theater 'just in case' they are needed to minimize environmental impact, can actually impede personnel safety and source control objectives, because they distract operations personnel, add congestion, and can impede surface access to the well location.'' (NPC 2019 Report at 19).

In the Beaufort Sea, the available open water operating season is limited to approximately 50 to 60 days across the historically active exploration area. (*id.* at 143). The study's analysis showed there is a high probability (90 percent) that drilling can be conducted safely for 70 days, from mid-August through October, in a majority of the historically active exploration area of the Beaufort Sea. (*id.* at 146).

In light of the information from the NPC reports and the Bratslavsky and SolstenXP study, and BSEE's consideration of that information, BSEE proposes to revise § 250.472 in the following manner:

• *Proposed Paragraph (a)—Complying with § 250.472 by Using an SSID*

The use of an SSID is not a new concept and was discussed in the 2016 Arctic Exploratory Drilling Rule.[47] Through the 2016 rulemaking comment process, stakeholders informed the Bureau that use of an SSID could help significantly reduce the risk of a release of hydrocarbons if the BOP system fails. At that time, BSEE focused more on permanent remediation to resolve a WCD event in the Arctic. Nonetheless, the Bureau agreed that an operator could request to use an SSID as an alternate procedure or equipment to the relief rig (80 FR 9940). Stopping short of requiring the use of an SSID, BSEE, instead, stated in the 2016 rule that it would consider the use of an SSID as an alternate procedure or equipment, under appropriate circumstances, if proposed for use with a jack-up (when surface BOPs are used). At that time, BSEE determined that, in the case where subsea BOPs are used in conjunction with floating drilling units, SSIDs would only be marginally effective or redundant (81 FR 46531). Since the publication of the 2016 rule, BSEE has reevaluated the use of SSIDs and the overall improved technology for similar components (BOPs). In this proposed rule, BSEE would allow operators the option to use an SSID based on BSEE's assessment of improved SSID design and operating requirements, including the ability to shut in a well over the winter ice season with a well cap. Additionally, BSEE would make this revision to potentially minimize environmental damage due to a prolonged ongoing well control event. An SSID is not a permanent solution for well remediation. However, it can provide a significantly quicker response time to address a well control event compared to drilling a relief well.

Consistent with the policy in E.O. 13783 to review existing regulations that potentially burden the development or use of domestically produced energy resources, BSEE re-considered the SSID more closely, in light of the SSID information from the NPC reports and the Bratzlavsky and SolstenXP study, to determine whether the device could address the issues the Bureau identified when promulgating the 2016 rule.

Drilling a relief well is a complex, time-consuming process. After setting up the drill rig and drilling begins, the process to intercept the original wellbore may take several weeks or more because the operator needs to drill deep enough at great precision to ensure interception of the original well. This delay increases the length of the time oil and other fluids within the original well could be flowing uncontrollably into the marine environment. There is no delay for operational use of an SSID compared to the process of using the relief rig or capping stack.

In this proposed rule, BSEE developed its proposed SSID requirements based on existing BOP equipment/technology whose performance and reliability has been tested, proven in a manner that is repeatable and reproducible, and has improved since promulgation of the 2016 rule. BSEE also proposes to require an SSID used in the Arctic OCS to operate independently from the BOP. This would be accomplished by requiring the SSID to have a redundant control system, independent from the BOP control system, and independent, dedicated subsea accumulators to operate the SSID. By having two independent, redundant components (*i.e.,* the BOP and the SSID) as part of the well control system, the overall reliability and effectiveness of the entire system increases. The following paragraphs describe BSEE's proposed requirements associated with the SSID, including the SSID's redundant control system (*i.e.,* under proposed § 250.472(a)(2)(ii)) and subsea accumulators (*i.e.,* under proposed § 250.472(a)(2)(iii)).

Although the NPC 2019 Report recommended that the use of an SSID and capping stacks replace the requirement for an SSRW capability, BSEE is not proposing to eliminate the relief rig and SSRW requirements. Rather, BSEE is proposing to maintain the relief rig and SSRW requirement as an option for the operator to meet the regulatory requirements of § 250.472. BSEE has determined that its regulations should provide options and flexibility to the operator (*i.e.,* an SSID or a relief rig) to fit its needs and plans to develop its Arctic OCS leases. There could be cases where the operator's drilling schedule may not align with the availability of an SSID. In such a case, the operator should have the option to elect to proceed by complying with the relief rig and SSRW requirements. If an operator does not complete its exploratory drilling operations during that open water operating season, the operator could come back during a subsequent open water operating season and use an SSID, if one has become available in time.

There could also be cases where two or more operators may plan to perform exploratory drilling operations during the same open water season. In such a case, each operator's drilling rig could serve as the other's relief rig. Under the existing regulations, BSEE would consider this type of a scenario to be in compliance with the relief rig and SSRW requirements. BSEE would not change that interpretation as part of this rulemaking. In a scenario like this, none of the operators would need to install an SSID, so long as there is an agreement among the operators that their drilling rigs will serve as a relief rig, if necessary. While it is not possible to identify every conceivable scenario, BSEE recognizes there could be other scenarios that are reasonably possible. Thus, it is appropriate to provide regulatory flexibility in order to accommodate an operator's drilling program. BSEE also retains its regulatory authority to approve alternate procedures or equipment if the proposed procedures or equipment either meet or exceed the level of safety and environmental protection required.

The term SSID is a broadly used industry term, and there is not a single, all-encompassing definition that establishes the scope and function of an SSID. In some cases, different terms are used to describe the device. For example, as stated earlier, the

[47] *See, e.g.,* 80 FR 9940 (''[BSEE] requests comments on alternative compliance approaches and specifically requests data on the performance of SIDs, including operational issues (such as timeframes needed to activate such alternatives). In particular, BSEE requests comments on appropriate staging requirements for a relief rig assuming that an SID has been installed at the exploration well. Comments are also requested on the need for an operator to have an in- season relief well drilling capability if an SID is used at a location that is not subject to ice scouring.'')

Bratslavsky and SolstenXP study refers to the device as a ''subsea intervention device,'' while some in the industry also refer to the SSID as a ''mudline closure device.'' Irrespective of these synonymous titles, BSEE uses the term SSID to refer to a fit-for-purpose device that may be used for different types of situations, including for well intervention applications, and can be used in different locations, including outside of the Arctic. However, for the purposes of Arctic OCS exploratory drilling from a MODU, BSEE is proposing to define the minimum acceptable capabilities and functions of an SSID. BSEE notes that, outside of the Arctic OCS, operators are contemplating using SSIDs for future projects, and SSIDs have already been approved for use in other parts of the OCS. The NPC 2019 Report notes that the requirement to drill an SSRW to mitigate the risk of a late season well control event continuing over the winter season is ''outdated.'' The 2019 report concludes that SSIDs and capping stacks are superior solutions that could stop the flow of oil and allow intervention through the original borehole before a relief well could be completed. (NPC 2109 Report at 19). The SSID requirements BSEE is proposing to establish in this proposed rule would not apply to projects outside of the Arctic OCS. The design requirements for those SSIDs would be based on the needs of a particular project and may or may not be similar to what BSEE is proposing in this proposed rule. BSEE requests comments on these SSID requirements as outlined in the proposed rule.

Under proposed paragraph (a) of § 250.472, if the operator elects to satisfy the requirements of this section by using an SSID, BSEE would require the operator to ensure that the SSID and well design (including the casing and cementing program) are designed to achieve a full shut-in, without causing an underground blowout or having reservoir fluids broach to the seafloor.

Currently, BSEE's regulations for SCCE under § 250.462 do not require all wells to be designed to achieve a full shut-in (*e.g.,* partial shut-in is acceptable) as there are methods to control the residual fluid flow into a surface production and storage system when a well is designed for partial shut-in. However, because BSEE is proposing that the SSID be designed to achieve full wellbore shut-in until kill operations are completed, it is important that the well design assures that the well will be able to withstand the associated loads for the entire time the SSID is closed (*e.g.,* prevents gas migration in the shut-in wellbore). If the wellbore is compromised during or after a full shut-in, an underground blowout or broach to the seafloor may occur. BSEE reviewed available incident data on loss of well control events,[48] and determined that, on average, five loss of well control events occurred each year on the OCS between 2007 and 2017.

The well design language in proposed paragraph (a) would also require the operator to account for the stresses and loads placed on the well from the equipment that may be required to regain control after a loss of well control event. This includes the SSID, BOP stack, and capping stack. It is imperative that all well components are designed to withstand all potential loads and stresses placed on the well, including those that may be required during well control situations and deployment of SCCE (*i.e.,* the well must be able to support a capping stack in addition to the other equipment required for normal operations).

The need for the operator to account for all potential loads placed on the well also includes consideration of conditions where a well would be shut-in over the ice season. For example, in typical well control operations, a BOP is used to stop the uncontrolled flow and shut-in the well. It remains shut-in for a relatively short period of time while well kill operations are implemented and, if needed, materials and personnel are mobilized to the rig.

For wells that may be shut-in for extended periods, the operator must consider the potential effects of gas expansion within the well. For example, in reservoirs containing gas, which is less dense than the liquids in the wellbore (*e.g.,* drilling mud, completion fluid, brine), the gas will migrate upward in the wellbore until it reaches the closed BOP. This gas exerts a lower hydrostatic pressure than the column of oil or drilling fluids in the wellbore, and more of the reservoir pressure is transmitted to the top of the wellbore as a result. As the hydrostatic pressure acting on the bubbles decreases, the bubbles expand.

As these bubbles continue to migrate and expand over time, the wellbore pressure profile increases. What was once a low pressure at the top of the well, with a hydrostatic pressure gradient below it, will eventually increase to reservoir pressure, increasing the downhole pressure. As the pressures in the wellbore increase, some of the liquid may bleed into the open formation(s). Eventually, the pressure may exceed the strength of the formation (fracture pressure) in the wellbore, potentially resulting in a fracture of the formation and an underground blowout. Because proposed paragraph (a) of § 250.472 contemplates allowing the operator to leave a well shut-in from one open-water season to the next (*i.e.,* in the case of a late season well control event), wells need to be designed to withstand this potential loading condition.

In a new paragraph (a)(1), BSEE proposes to establish performance-based design requirements for the SSID. BSEE would require the operator to ensure that the SSID is designed to:

(1) Close and seal the wellbore, independent of the BOP;

(2) Perform under the maximum environmental and operational conditions anticipated to occur at the well;

(3) Be left on the wellhead in the event the drilling rig is moved off location (*e.g.,* due to storms, ice incursions, or emergency situations);

(4) Preserve isolation through the winter season without relying on the elastomer elements of the rams (*e.g.,* by using a well cap) and allow re-entry during the following open-water season; and

(5) In the event of a loss of well control, preserve isolation until other methods of well intervention may be completed, including the need to drill a relief well.

BSEE's analysis of loss of well control events data indicates that the most common methods employed to regain control of a well include pumping mud or cement into the uncontrolled well or activating mechanical well control equipment (*e.g.,* blowout preventer).

These SSID design requirements would help ensure the device is capable of shutting in and containing all fluids within the wellbore for an entire ice season (in the case of a loss of well control event too late in the open-water season to provide enough time for the operator to perform well kill or plug and abandonment operations). BSEE is basing the proposed design requirement for the SSID to be capable of preserving isolation through the winter season without relying on the elastomer elements of the rams (*e.g.,* by using a well cap) on information it gained from the Kara Sea project. BSEE understands that the SSID used in the Kara Sea project was capable of preserving isolation over an entire ice season because it was designed to have a metal-to-metal cap installed on top of the SSID, after the BOP is detached and all equipment is moved off of the drill site. BSEE understands that isolation could

[48] See, BSEE's website at *https://www.bsee.gov/stats-facts/offshore-incident-statistics.*

not be achieved over the ice season if the shut-in relied solely on the elastomer elements of the rams. The design requirements would also ensure the SSID will allow for re-entry to perform well recovery operations during the following open water season.

In a new paragraph (a)(2), BSEE proposes to require that the operator's SSID include the following equipment:

(1) Dual shear rams, including ram locks; one ram must be a blind shear ram;

(2) A redundant control system, independent from the BOP control system, that includes ROV (remotely operated vehicle) capabilities and a control station on the rig;

(3) Independent, dedicated subsea accumulators with the capacity to function all components of the SSID; and,

(4) Two side inlets for intervention, one of which must be located below the lowest ram on the SSID.

The dual shear ram requirement in proposed paragraph (a)(2)(i) would ensure that the SSID is capable of shearing through drill pipe, sealing the wellbore, and containing the fluids before they can escape during a loss of well control event. BSEE notes that the NPC 2019 Report describes the SSID as having shearing/sealing rams. In fact, when describing the SSID used in the Kara Sea Project, the report explains that the device utilized dual blind shear rams. While proposed paragraph (a)(2)(i) would require only one of the rams to be a blind shear ram, BSEE is seeking comment on the advisability of requiring dual blind shear rams on the SSID. As described in the bow-tie diagram of the NPC 2019 Report, the SSID is the last line of prevention to minimize the impacts of an event. (NPC 2019 Report at 14).

The redundant control system requirements in proposed paragraph (a)(2)(ii) would ensure there is reliability in the system and that the SSID will function when needed in an emergency situation. This proposed requirement is intended to align with the existing requirement in existing § 250.734(a)(2), which requires subsea BOPs to have a redundant control system to ensure proper and independent operation of the BOP system. With respect to the requirement that an SSID have a separate control station on the rig that is independent from the BOP control system located on the rig, it is important for the SSID functions to be controlled by personnel directly involved in the drilling process to allow for an appropriate response from a ''situationally aware'' individual. Therefore, while BSEE is proposing to require the SSID control system to remain independent of the BOP control system, it would not require those systems to be located in separate locations.

BSEE is seeking comment on whether the proposed requirement in paragraph (a)(2)(ii) is appropriate for the SSID or whether there are additional ways to enhance the system's reliability. For example, BSEE is contemplating whether it may be more appropriate to require the SSID's redundant control system capabilities to be separate from the ROV's capabilities. BSEE is also considering, as part of the final rule, requiring the SSID control systems to be consistent with the fully redundant control system requirements described in American Petroleum Institute (API) Specification (Spec.) 16D (*e.g.,* yellow pod and blue pod). More specifically, BSEE is further considering whether there should be an additional manual method (separate from the redundant control system) to close the SSID's rams with the ROV and whether it may be appropriate to require a standby or tending vessel with an ROV. These measures could address cases where the SSID's control system on the drilling rig is not available (*e.g.,* due to failure or an evacuation of the rig).

The requirement in proposed paragraph (a)(2)(iii) for SSIDs to have independent, dedicated subsea accumulators with capacity to function all components of the SSID would help ensure that, if the BOP system fails, the SSID will have the capabilities to function as needed, independent of the BOP's accumulator system. The requirement in proposed paragraph (a)(2)(iv) for SSIDs to have two side inlets, with one of the inlets located below the lowest ram on the SSID, would allow for re-entry through the SSID to perform well intervention operations. Side inlets allow the operator to pump fluids into the well to kill the well, before opening the blind shear ram to perform additional well intervention operations.

In proposed paragraph (a)(3), BSEE would require the SSID to include ROV intervention equipment and capabilities to function the SSID. BSEE regulations currently include requirements for ROV intervention capabilities in relation to a BOP's functionality. BSEE is proposing similar requirements for the SSID because the SSID functions similarly to a BOP. Under proposed paragraph (a)(3), the ROV equipment and capabilities must:

(1) Be able to close each shear ram under the Maximum Anticipated Surface Pressures (MASP), as defined for the operation;

(2) Include an ROV panel that is compliant with API RP 17H (as incorporated by reference in § 250.198);

(3) Meet the ROV requirements in existing § 250.734(a)(5); and,

(4) Have the ability to function the SSID in any environment (*e.g.,* when in a mudline cellar).

The requirement in proposed paragraph (a)(3)(i) for the ROV to be able to close each shear ram under the operation's defined MASP would ensure that the operator is able to remotely close (through the ROV) each shear ram on the SSID and seal the well, which are the most critical functions during a well control event. The requirement in proposed paragraph § 250.472 (a)(3)(ii) for the ROV to have panels that are compliant with API RP 17H would ensure that the operator's ROV capabilities for the SSID follow BSEE's existing ROV panel requirements for BOP systems. API RP 17H provides recommendations and overall guidance for the design and operation of ROV tooling used on offshore subsea systems (*e.g.,* provision for high flow Type D hot stabs). This guidance is critical to ensuring safe and reliable ROV operations. In conjunction with the proposal in paragraph (a)(3)(ii) to require the operator's ROV panels to be compliant with API RP 17H, BSEE proposes to add the citation for proposed § 250.472(a)(3) to § 250.198(e)(73). Section 250.198(e)(73) documents the locations in the regulations where API RP 17H is incorporated by reference as a regulatory requirement, which would include § 250.472(a)(3) under this proposed rule. Adding the citation for § 250.472(a)(3) to § 250.198(e)(73) would clarify that API RP 17H is a regulatory requirement when complying with § 250.472 and is subject to BSEE oversight and enforcement in the same manner as other regulatory requirements.

The requirement in proposed paragraph (a)(3)(iii) for the operator to meet the requirements in existing § 250.734(a)(5) would ensure that the operator has a trained ROV crew on each rig unit. The crew must ensure that the ROV is maintained and capable of carrying out the necessary tasks during emergency operations and be trained in operating the ROV, including stabbing into the ROV intervention panel on the SSID. The crew must also have the capability to communicate with designated rig personnel, who are knowledgeable about the SSID's capabilities.

The requirement in proposed paragraph (a)(3)(iv) for the ROV to be capable of functioning the SSID in any environment is meant to address those cases where it may be necessary to place the SSID in an enclosed or restricted environment. For example, if the SSID is used in an area with ice scouring or with deep ice keels, the SSID would be placed in a mudline cellar. If the ROV panels are attached to the SSID, the ROV may not be able to access the panels if there is not enough space in the cellar. The operator must ensure that the ROV has the capabilities to address these types of scenarios. BSEE is aware of current projects that are evaluating positioning the ROV panels away from the SSID. The ROV would function the SSID from the remote panel, which would be hardwired to the SSID. In addition, it is possible for a mudline cellar to be constructed via a dragline. In such a case, the mudline cellar could be constructed wide enough to provide adequate space for the ROV to access the panel if the panel was attached to the SSID. BSEE proposes to make the requirement in proposed paragraph (a)(3)(iv) flexible, recognizing that there are multiple ways an operator could address this type of concern.

In general, however, BSEE is seeking comment on the feasibility of installing an SSID below a subsea BOP in cases where the SSID would also be installed in a mudline cellar. BSEE's current regulations at §§ 250.734(a)(13) and 250.738(h) require placement of subsea BOP systems in mudline cellars when drilling occurs in areas subject to ice-scouring. In addition, proposed § 250.720(c)(2) requires placement of the wellhead in a mudline cellar in areas subject to ice-scouring. BSEE is requesting more information about whether there are any other operational or installation challenges that the operator may encounter when attempting to effectively operate the SSID in this environment. If so, what are those challenges, and how could they be addressed?

BSEE understands that the SSID used in the Kara Sea could be manually activated using acoustic technologies. While such technologies are available to function the SSID from a remote location, BSEE is proposing to require use of an ROV, as described in proposed paragraph (a)(3). BSEE understands that ROVs are more reliable for this type of application. However, BSEE requests that commenters provide any information that demonstrates the reliability of acoustic (or other) technologies to actuate an SSID from a remote location.

Furthermore, although BSEE is not proposing to require the SSID to have a self-actuating function, the Bureau is contemplating whether one may be necessary for certain emergency situations. BSEE is aware that in the Arctic OCS, it is possible for a drilling vessel to sink and allide with (*i.e.,* strike against) the top of a wellhead during a loss of well control event (Bratslavsky and SolstenXP at 17). As discussed in the previous section, all exploratory drilling in the Beaufort Sea and the Chukchi Sea has taken place in waters less than 167 feet deep, and as recent as April 2020,[49] there were active leases in the Beaufort Sea where an SSID could have been deployed. These leases were located in water depths less than approximately 170 feet deep. In these water depths, during an emergency, a vessel could sink before the BOP or SSID can be activated. A self-actuating system incorporated into the SSID could potentially address this problem.

One option BSEE is considering is whether it may be appropriate to establish an autoshear and deadman system requirement for the SSID. The intent would be to address those emergency situations, such as when a sunken MODU allides with the wellhead, where the SSID could no longer be functioned via the ROV (due to lack of access) or a control station on the drill ship. BSEE's regulations already address autoshear and deadman systems for subsea BOPs. Existing § 250.734(a)(6)(i) requires subsea BOPs to have an autoshear system that is designed to automatically shut-in the wellbore in the event of a disconnect of the lower marine riser package (LMRP). Also, existing § 250.734(a)(6)(ii) requires a deadman 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 the subsea control pods, respectively. However, BSEE did not propose this requirement for SSIDs in this rulemaking. The SSID is meant to be a backup to the BOP, and it is not necessary for the SSID to have the same automatic emergency functions as the BOP.

There could potentially be negative consequences if both systems were to automatically function. For example, there could be a situation where the BOP's autoshear or deadman systems function, but they are not able to shut-in the well because a non-shearable drill string is positioned across the rams. If the subsea BOP rams are experiencing this issue, then the SSID may also encounter the same problem, depending on the part of the drill string that is across the rams at that time. In this scenario, it would be more appropriate to assess the situation to determine whether other well intervention operations could be performed to address the position of the drill string, before activating the SSID.

Regardless of these challenges, BSEE is seeking comment on what fail-safe mechanism(s) may be appropriate to address cases where the BOP fails and the SSID is inaccessible by an ROV or a control station. If an autoshear system or a deadman system are appropriate fail-safe mechanisms to add to the SSID, BSEE is seeking input on what criteria should be used to function these systems, to ensure the system does not function at the wrong time or interferes with or impacts the BOP's autoshear and deadman systems.

BSEE is also seeking comment on how to ensure that the SSID will be able to preserve isolation over the winter season in the event of a late-season emergency incident, such as a sunken drillship. As previously mentioned, BSEE understands that prior SSIDs have planned for long-term isolation through installation of a metal-to-metal cap (*i.e.,* a well cap) on the SSID before leaving the device on the seafloor over the winter season. In the case of a late-season emergency situation that prevents access to the SSID to install a metal-to-metal cap, how would isolation be preserved through the winter season?

In addition, BSEE is soliciting comment on whether the regulations should require use of an autoshear or deadman system in cases where these systems are not built into the BOP's system. As previously mentioned, BSEE's autoshear and deadman system requirements currently apply to subsea BOPs. There is no current requirement to use an autoshear or deadman system when surface BOPs are used. BSEE would expect that if an operator uses a surface BOP, the operator would still install the SSID on the seafloor. BSEE seeks comment on whether it would be appropriate in such a case to require use of an autoshear or deadman system on the SSID. If so, what criteria should BSEE apply to the functioning of the autoshear or deadman systems in an environment where a surface BOP is used? Furthermore, BSEE welcomes any other comments, unrelated to autoshear or deadman systems, regarding use of a surface BOP.

With respect to installation of the SSID, BSEE proposes in paragraph (a)(4) to require operators to install the SSID:

(1) Below the BOP;

[49] In April 2020, the only leases with potential projects that would be subject to the Arctic OCS's SSID or SSRW requirements were relinquished. However, there are other active leases in the Beaufort Sea located nearer to the shore in shallower waters where exploration and development projects are actively being pursued (primarily through man-made gravel islands).

(2) At or before the time they install their BOP; and

(3) In a way that will provide protection from deep ice keels in the event it must remain in place over the winter season (*e.g.,* installed in a mudline cellar).

Installing the SSID below the BOP would allow for quick detachment of the BOP and other equipment above the SSID, which would be critical when moving off of a location for emergency purposes. With respect to timing of the SSID's installation, the operator would be required to install the SSID at or before the time they install the BOP. The proposed requirement for the SSID to be installed in a way that will provide protection from deep ice keels would help ensure that the device is not damaged by ice in areas of ice scour. As previously discussed, this could be accomplished by placing the SSID in a mudline cellar. In complying with this proposed requirement, the operator must also consider situations where the drill site is not located in an ice scour area, but could experience ice floes with keels deep enough to clip and compromise the SSID if left on the seafloor over the winter season.

In a new paragraph (a)(5), BSEE proposes to require the operator to test the SSID according to the BOP testing requirements in § 250.737, *What are the BOP system testing requirements?* The SSID's testing requirements should align with the BOP testing requirements since, as previously mentioned, the SSID functions similarly, and in addition, to a BOP. This testing would aid in predicting future performance of the SSID to ensure that the device will function when needed during an emergency situation. While BSEE proposes to align the SSID testing requirements with the Bureau's existing BOP testing requirements, BSEE welcomes input on whether there are more appropriate and reliable testing methods. For example, what testing procedures have been used in the past to test an SSID when it was deployed? For future operations, what testing procedures are being developed specifically for an SSID? What testing procedures should be applied to SSIDs, and why?

Overall, BSEE intends for the SSID to provide time for the operator to marshal the equipment and materials necessary to permanently address a well control event, without the constraints of seasonal ice coverage, and to prevent the potential environmental impacts that could occur if an out of control well was allowed to flow over the season when the operator would not have access to the site due to ice. The SSID, along with the proper well design, would allow the well to be shut in over the ice season without requiring additional vessels and the situation addressed permanently in the following open water season. It would also allow the operator the time necessary to complete the intervention, without the well flowing, if unforeseen problems are encountered.

Collectively, the SSID's design requirements; equipment specifications; ROV intervention capabilities; installation requirements; and testing requirements; together with the additional well design requirements, would help ensure that the device will function when needed during an emergency situation and will be capable of controlling the well over the ice season, if necessary, until the operator returns to perform well intervention operations during the following open-water season. In connection with that well intervention operation, BSEE may still exercise its existing authority to also require the operator to drill a relief well to permanently plug and abandon the out-of-control well, if needed. BSEE reviewed recent incident data from 2013 to 2017, which may be accessed on BSEE's website at *https://www.bsee.gov/stats-facts/offshore-incident-statistics,* to try to identify any past incidents involving the use of a BSEE directed relief well to remedy the loss of well control. Aside from the Macondo well incident in 2010, one incident in 2013 required the drilling of a relief well (see *https://www.bsee.gov/newsroom/latest-news/statements-and-releases/press-releases/drilling-of-relief-well-begins-at-south*). Other loss of well control events during that timeframe were successfully remedied with conventional well control methods. These incidents occurred in the Gulf of Mexico and were controlled by either circulating heavier weighted muds into the well or closing the BOP (or both), to control pressures within the well. BSEE would evaluate the individual circumstances associated with each case to make this determination. For these reasons, BSEE's proposed changes to § 250.472 would maintain safety and environmental protection, though BSEE invites comment on the technical feasibility of such requirements.

BSEE is seeking comment on whether the use of an SSID, particularly in a case where a subsea BOP is deployed, could present operational or installation challenges. For example, if the well is not located in an ice scour area and the BOP system, including the LMRP, and the SSID are placed on the seafloor, then these pieces of equipment could get as tall as 88 feet when installed (BOP approximately 70 feet + SSID approximately 18 feet). In addition, the bottom of a ship's hull, in the case where a drillship is used, may extend as much as 40 feet into the water from the sea surface. Historically, drilling in the Beaufort Sea and the Chukchi Sea has occurred in waters less than 167 feet deep. With as much as 128 feet of water column taken up by the BOP system, SSID, and ship's hull, very little space remains for operations between the bottom of the ship and the top of the well control system. BSEE seeks comment on what sorts of challenges operators have faced or would anticipate facing in the scenario just described. BSEE would also like to know how operators addressed those challenges in the past or could address them for future operations, taking into account the unique characteristics and extreme conditions of the Arctic OCS.

BSEE is also generally seeking comment on its proposed changes to § 250.472. For example, BSEE is seeking comments on how well design could be better addressed in this rulemaking to enhance overall safety of operations on the Arctic OCS. Is the well design requirement proposed in paragraph (a) adequate to address the situations that may be encountered if a well is shut-in with an SSID over a winter season? As previously described, there could be cases where the wellbore pressure profile may increase to reservoir pressures at the top of the well over the course of a winter season. What other scenarios should BSEE consider that could occur in the well over the ice season that could be addressed in proposed paragraph (a)?

- *Proposed Paragraph (b)—Complying with § 250.472 by Having Access to a Relief Rig*

As discussed earlier, BSEE proposes to combine existing paragraphs (a) and (b) into a single, new paragraph (b), *Relief Rig,* for organizational purposes because both existing paragraphs cover relief rigs. Combining existing paragraph (a) into proposed paragraph (b) would not be a substantive modification to BSEE's regulations because the specific requirements from existing paragraph (a) would remain unchanged. More specifically, the provision in existing paragraph (a) that requires the operator's relief rig to comply with all other requirements of 30 CFR part 250 that pertain to drill rig characteristics and capabilities, and requires the relief rig to be able to drill a relief well under anticipated Arctic OCS conditions, would be relocated to proposed paragraph (b)(1). The provision in existing paragraph (a) that provides that the Regional Supervisor may direct the operator to drill a relief well in the event of a loss of well control would be relocated to proposed paragraph (b)(2).

○ *Last Casing Point Prior to Penetrating a Zone Capable of Flowing Hydrocarbons in Measurable Quantities*

Substantively, BSEE proposes to revise the requirements in existing paragraph (b) that prescribe the availability of the relief rig. BSEE would maintain the requirement for the operator to have access to a relief rig, different from its primary drilling rig, when drilling or working below the surface casing. However, BSEE proposes to add a new provision to the newly rearranged proposed paragraph (b) stating ''However, the Regional Supervisor will approve delaying access to your relief rig until your operations have reached the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities, provided that you submit adequate documentation (such as, but not limited to, risk modeling data, off-set well data, analog data, seismic data), with your APD, demonstrating that you will not encounter any abnormally high-pressured zones or other geological hazards. The Regional Supervisor will base the determination on any documentation you provide as well as any other available data and information.''

BSEE would also add new language at the beginning of existing paragraph (b) that says ''*Relief Rig.* If you choose to satisfy this requirement by having access to a relief rig, you must have access to your relief rig at all times when you are drilling below or working below the surface casing during Arctic OCS exploratory drilling operations.'' This language would simply clarify that if the operator chooses to use a relief rig to comply with proposed § 250.472, it must have access to its relief rig at all times when drilling below or working below the surface casing. The changes described in this paragraph would be shown as a general requirement in proposed paragraph (b).

BSEE's proposed revisions to paragraph (b) would potentially provide an opportunity for the operator to adjust the point in time during its operations when it must stage its relief rig. If the operator is able to demonstrate to BSEE that the operations it plans to conduct below the surface casing would not encounter any abnormally high-pressured or other geologic hazards before reaching the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities, then BSEE would allow the operator to delay staging of its relief rig until reaching that point.

The changes BSEE is proposing would make proposed paragraph (b) of § 250.472 and proposed paragraph (a) of § 250.471 consistent, with respect to providing a potential opportunity to the operator to delay access to its SCCE (as described in § 250.471(a)(1) and proposed § 250.471(a)(2) and (3)) until its operations have reached the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities, so long as the operator submits adequate documentation, with its APD, demonstrating that it will not encounter any abnormally high-pressured zones or other geologic hazards before that casing point.

The existing requirement in § 250.472(b) pertaining to the availability of a relief rig does not take into consideration that the operator may demonstrate, based on geologic and engineering analyses, that there could be zones below the surface casing that are not hydrocarbon-bearing or that have minimal or no potential to flow hydrocarbons in measurable quantities during drilling operations. In many cases, operators do not anticipate or encounter flowable hydrocarbons in measurable quantities until the target productive formation is reached. For example, a surface casing shoe setting depth for an Arctic OCS exploration well could be only 1,500 feet deep, but the hydrocarbon bearing formation may be thousands of feet deeper below that point. The existing regulations require the operator to stage its relief rig when drilling or working below the surface casing, even though geologic and engineering risk analyses the operator must submit as part of their APD may indicate that there is little or no potential for hydrocarbons to escape the formation and flow into the well prior to reaching the targeted productive formation. In such circumstances, the operator could safely drill for thousands of feet below the surface casing without any identifiable need for a relief rig.

This proposed change would, when appropriate, eliminate the need for the operator to stage its relief rig while drilling through low risk, non-productive sections of the well below the surface casing. Arctic regional pore pressure modeling conducted by BOEM for an area in the Beaufort Sea identifies a general uniformity following an average pressure gradient (*i.e.,* normally pressured) up to approximately 7,500 feet to 8,500 feet, subsea. The typical reservoirs targeted for exploration in the Arctic are usually located at less than 8,000 feet. In the GOM, there are many different geological features that can affect the pressure profiles and potentially create abnormal pressures (*e.g.,* salt domes, and shallow water flow areas).

An extensive amount of geophysical data already exists for certain areas of both the Beaufort and Chukchi Sea Planning Areas, and there has been extensive drilling in certain areas of the Beaufort Sea Planning Area. In the known geologic conditions of the U.S. Arctic, operators have a good understanding of the locations of reservoirs that they will encounter, which can be relatively shallow and normally pressured to certain depths. Therefore, it may not be necessary to have a relief rig immediately available when drilling through zones below the surface casing that do not have abnormally high formation pressures or contain other geological hazards, and do not have the potential to flow hydrocarbons in measurable quantities as they are penetrated.

However, because geologic conditions are not uniformly normally pressured throughout the Arctic OCS, BSEE is maintaining the existing requirement to have the relief rig staged when drilling or working below the surface casing. At the same time, BSEE does not want to discount the possibility that future projects would not need to have the relief rig staged until reaching the last casing point prior to penetrating a zone capable of flowing hydrocarbons.

The criteria BSEE proposes to rely on—that the operator can demonstrate to BSEE that it will not encounter ''abnormally high-pressured zones or other geologic hazards''—to determine whether to grant an exception accounts for those downhole risks that could lead to a blowout and may require the use of a relief rig. With respect to abnormally high-pressured zones, BSEE is concerned that there could be a case where a kick (an influx, or flow, of formation fluid from the high-pressured zone entering into the wellbore) is not controlled and could lead to a blowout. While there are means of mitigating the risk of a kick, (*i.e.,* overbalanced drilling), the relief rig needs to be readily available if heavier weight drilling muds, the BOP and SSID, if applicable, fail to control the well.

There could be other geologic hazards, such as fractured or high permeability zones, that may also pose a risk, particularly if those zones contain hydrocarbons. It is possible that normally pressured zones may be highly permeable or contain fractures, in which lost circulation can occur. This could cause a dynamic effect where drilling mud flows into the permeable formation and causing the circulating pressure to decrease below the zone's pore pressure resulting in formation fluids flowing into the well bore. This may lead to a loss of well control. The relief rig needs to be readily available if heavier weight drilling muds, the BOP, and the capping stack, fail to control the well.

However, if the operator is able to demonstrate that a highly permeable or fractured zone is predicted to only contain water, BSEE would consider allowing the operator to delay the staging of its relief rig. Under this scenario, the operator would be able to use the diverter system in conjunction with the BOP system to maintain safety and environmental protection because it would be unlikely for hydrocarbons to be released into the environment. The diverter system consists of a mechanical device similar to a BOP annular preventer. The diverter system is used to divert gases, fluids, and other materials flowing from the well, away from facilities and personnel. Also, an operator would pump fluid loss materials into the well to bridge the formation to reduce its permeability and allow drilling muds to isolate the formation from the well. To permanently address the incident, the operator could also install a liner or set a new casing point at the interval where that highly permeable or fractured zone is located. As requested in the section-by-section discussion of § 250.471, BSEE would like to know whether there are more appropriate criteria, other than ''abnormally high-pressured zones or other geologic hazards,'' the Bureau should use to determine whether to allow the operator to delay its staging of the relief rig.

BSEE's proposed regulatory language describing the types of documentation it would consider adequate to demonstrate that abnormally high-pressured zones or other geologic hazards would not be encountered before reaching the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities— ''such as, but not limited to, risk modeling data, off-set well data, analog data, seismic data''—is not meant to be an exhaustive list. BSEE would accept any other types of documentation the operator may provide that will help its demonstration. BSEE does not anticipate this submission requirement would lead to a significant information collection burden on the operator because it is normal practice for operators to gather these types of information in order to develop and design an offshore exploration drilling project in the Arctic OCS. BSEE is requesting comment on what other types of information could be used to demonstrate the absence of abnormally pressured zones or other geologic hazards, and how burden on the operator could change—increase or decrease—if BSEE were to require its submission.

At the APD stage, BSEE would evaluate the operator's documentation along with other accompanying geologic and engineering information/analyses that must be submitted as part of their APD. BSEE would also take into consideration any other available G&G information, such as information gathered from prior drilling operations in the area (*e.g.,* well log and pressure testing information), and any other applicable geophysical information (*e.g.,* seismic data). BSEE makes clear in its proposed regulatory language that the Regional Supervisor will base the determination for whether to allow the operator to delay staging of its relief rig on the documentation the operator submits as well as any other available data and information.

BSEE is also considering an alternative regulatory approach whereby the Bureau would instead revise existing paragraph (b) by replacing ''surface casing'' with ''last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities.'' This option would adjust the point in time during operations when the operator must stage its relief rig. This alternative regulatory change would, instead, require the operator to stage its relief rig before drilling below or working below the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities.

Under this regulatory option, BSEE would evaluate the geologic and engineering information/analysis the operator must submit as part of its APD, while also taking into consideration any other available G&G information the Bureau may have (*e.g.,* off-set well data, such as well logs and pressure testing information, or geophysical information, such as seismic data). Based on these different sources of information, BSEE would determine whether there may be a need for the operator to position the capping stack at an interval earlier than last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities.

There may be cases where the operator or BSEE may not have sufficient G&G or analogous well data during the permit review process on a proposed project to provide an adequate level of certainty regarding anticipated formations that may be encountered prior to reaching the targeted productive formation. Therefore, BSEE is also contemplating, as part of this regulatory option, a clarification that the Regional Supervisor may require the operator to stage its relief rig prior to drilling below or working below the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities if BSEE determines there is insufficient G&G or analogous well data.

For example, there may be insufficient G&G or analogous well data in cases where there have been a limited number of wells drilled within proximity to the planned well. In most cases, G&G and analogous well data are gathered from multiple sources. However, the same sets and amounts of data and information may not be available for each area, well, or project. There is no single set of criteria for determining the sufficiency of G&G or analogous well data. The more data that are available from sources near to the proposed drilling location, the greater confidence BSEE will have in the G&G interpretations. BSEE wants to ensure the operator has the most accurate data to make determinations about where the zones capable of flowing hydrocarbons in measurable quantities are located.

This alternative regulatory option would maintain the same level of safety and environmental protection in comparison to BSEE's proposed regulatory change. The decision on whether it is appropriate to delay positioning of the capping stack below the surface casing resides with BSEE. BSEE, ultimately, may not allow the operator to delay staging of the relief rig if there are potential risks below the surface casing that may require immediate relief rig deployment. However, the distinction under this regulatory option is that the operator would not need to specifically demonstrate that abnormally high-pressured zones or other geologic hazards would be encountered above last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities. BSEE would be responsible for making that determination.

BSEE is specifically soliciting comments about its views of the benefits or disadvantages of this regulatory option and the need for the operator to verify on a case-by-case basis which zones are incapable of flowing hydrocarbons in measurable quantities.

○ *Expected Seasonal Ice Encroachment at the Drill Site*

In the 2015 proposed Arctic Exploratory Drilling Rule, BSEE determined that, because Arctic OCS exploratory drilling operations from a MODU take place only during the open water season (*i.e.,* that period of time in the summer and early fall when ice hazards can be physically managed and there is no continuous ice layer over the water), it was critical to ensure that drilling (including relief well drilling) and other operations affected by sea ice are concluded before ice encroachment. Ice encroachment may complicate or prevent drilling, transit, and oil spill response operations. However, the analysis from the Bratslavsky and SolstenXP study shows that the sea ice capabilities of an ice class MODU and its support vessels can extend the currently available open-water operating seasons in the Chukchi and Beaufort Seas, depending on the drilling location within each planning area (*id.* at 143). Therefore, BSEE proposes to eliminate the reference to ''expected seasonal ice encroachment'' at the drill site in existing paragraph (b). BSEE, however, would retain the requirement clarifying that the relief rig must be different than the operator's primary drilling rig and that the relief rig must be staged in a location such that it can arrive on site, drill a relief well, kill and abandon the original well, and abandon the relief well no later than 45 days after the loss of well control. This proposed regulatory change would effectively extend the drilling season in those cases where the operator's MODU and associated support vessels are capable of safely operating beyond the period when seasonal sea ice begins to encroach at a drill site. The operator would no longer need to plan for their well operations to end in time to complete a relief well prior to the date when sea ice is expected to encroach on the drill site. The operator would, instead, have to plan to end its operations with sufficient time to complete its relief well prior to the anticipated date when sea ice conditions at the drill site are approaching the ice classification capability and rating limits of the operator's vessels.

BSEE and BOEM would evaluate the ice classification capabilities and limitations of the operator's MODU and associated support vessels using existing permitting and review processes. For example, through BOEM's EP review process, the operator is required under existing § 550.220(c)(6) to specify when it anticipates completing onsite operations and when it anticipates terminating drilling operations. In addition, § 550.220(c)(1) requires the operator to describe how it will design and conduct its exploratory drilling activities in a manner that accounts for Arctic OCS conditions. Furthermore, in the EP regulations at proposed § 550.220(c)(1), BOEM would require the operator to submit a description of how all vessels and equipment will be designed, built, and/or modified to account for Arctic OCS conditions and how such activities will be managed and overseen as an integrated endeavor. This preamble discusses this proposed regulatory change in more detail later. Collectively, this information provided in an EP would allow BOEM (in conjunction with BSEE) to evaluate the capability of the operator's equipment, including its vessels and procedures to manage and mitigate risks associated with Arctic OCS conditions.

At the APD stage, BSEE would also review the capabilities of the operator's MODU and associated supporting vessels. Existing paragraph (a)(2) of § 250.470, *What additional information must I submit with my APD for Arctic OCS exploratory drilling operations?* requires the operator to describe how it plans to prepare its equipment, materials, and drilling unit for service in the environmental, meteorological, and oceanic conditions it expects to encounter at the well site and how its drilling unit will be in compliance with the requirements of existing § 250.713, *What must I provide if I plan to use a Mobile Offshore Drilling Unit (MODU) for well operations.* Paragraph (d) of § 250.713 requires the operator, when using a MODU for well operations, to provide the current Certificate of Inspection (for U.S.-flag vessels) or Certificate of Compliance (for foreign-flag vessels) from the USCG, as well as a Certificate of Classification. The operator must also provide current documentation of any operational limitations imposed by an appropriate classification society. As discussed earlier in this section, the Bratslavsky and SolstenXP study notes that a vessel's capabilities are identified by the ice classification for the vessel, which is provided by marine classification societies such as ABS and DNV GL. BSEE would evaluate the information required under existing §§ 250.470(a)(2) and 250.713(d), together with BOEM's approval of the operator's end-of-season date(s) in the EP, to verify whether the vessels' capabilities and limitations can support extending operations beyond when seasonal ice is expected to arrive at the drill site. However, in no case will BSEE approve a permit that proposes to use a vessel that does not meet the existing requirements of § 250.713, including providing a current certificate of inspection or compliance from the USCG.

Finally, while BSEE is proposing these revisions to § 250.472, BSEE is seeking comment on whether there are other appropriate approaches to well control operations in the Arctic, including alternative equipment/technology or performance standards. For example, although the NPC 2019 Report recommends accepting the use of an SSID in place of the requirement for SSRW capability, it also recommends replacing the relief rig and SSRW requirements with requirements that specify the desired outcome (*i.e.,* to stop the flow of a well and allow the operator to propose equivalent technology and demonstrate its capabilities). (NPC 2019 Report at 30). BSEE assumes that the NPC recommends specifying a desired performance-based outcome in the regulations that would allow the operator to propose and demonstrate technologies capable of meeting that standard at the permitting stage, rather than prescribing a particular technology, such as a relief rig.

Subpart G—Well Operations and Equipment

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

BSEE proposes to delete the last sentence in existing paragraph (c)(2) that states ''BSEE may approve an equivalent means that will meet or exceed the level of safety and environmental protection provided by a mudline cellar if the operator can show that utilizing a mudline cellar would compromise the stability of the rig, impede access to the well head during a well control event, or otherwise create operational risks.'' In its place, BSEE proposes to insert a new sentence that states ''You may request, and the Regional Supervisor may approve, an alternate procedure or equipment in accordance with §§ 250.141 and 250.408.'' BSEE, however, would preserve the basic requirement in in paragraph (c)(2) for the operator to use a mudline cellar or an equivalent means if there is indication of ice scour. The regulatory change BSEE is proposing in this section would make clear that BSEE could approve the equivalent means of doing so in accordance with §§ 250.141, *May I ever use alternate procedures or equipment?* and 250.408, *May I use alternate procedures or equipment during drilling operations?*

The new language that BSEE proposes to insert reiterates longstanding regulatory provisions contained in §§ 250.141 and 250.408 that describe what procedures the operator must follow and standards it must meet to receive BSEE's approval of a request to use alternate procedures or equipment to those required by regulation. Section

250.141 allows the BSEE District Manager or Regional Supervisor to approve the use of any alternate procedures or equipment that the operator may propose if the proposal provides a level of safety and environmental protection that equals or surpasses BSEE's current requirements. It also describes the types of information the operator must submit or present to BSEE when requesting to use alternate procedures or equipment. Section 250.408 requires the operator to identify and discuss their proposed alternate procedures or equipment in their APD.

Since the issuance of the 2016 Arctic Exploratory Drilling Rule, BSEE learned that there is an industry misconception that the last sentence in existing paragraph (c)(2) means that the operator would be required to use a mudline cellar in all cases, except when the operator can prove that the mudline cellar would present an operational risk—effectively narrowing the scope of §§ 250.141 and 250.408 in this context. However, BSEE did not intend that language to constrain the contexts in which operators could seek approval of alternatives to the mudline cellar requirement. Rather, in response to commenters expressing concern that use of a mudline cellar may create operational risks in certain contexts, BSEE introduced that language to make clear that alternate approaches were available in those contexts, while at the same time highlighting the general flexibility available under § 250.141, *May I ever use alternate procedures or equipment?* (*see* 81 FR 46507 and 46510). The last sentence in existing paragraph (c)(2) was not intended to, and did not, restrict or preclude use of the longstanding options for seeking approval of alternate procedures or equipment under §§ 250.141 and 250.408, which do not necessarily require a demonstration of operational risk. Thus, this proposed change would clarify that the operator has more flexibility to propose alternate solutions to the mudline cellar requirement under a broader range of circumstances than those described in the last sentence of existing § 250.720(c)(2). An operator could still base such a request on the same grounds that BSEE described in the language that we propose to delete (*i.e.,* that installation of a mudline cellar in a specific case would cause operational risks).

B. Key Revisions Proposed by BOEM

Title 30, Chapter V, Subchapter B, Part 550, Subpart B—Plans and Information Definitions. (§ 550.200)

BOEM is proposing to eliminate the definition of the term ''Integrated Operations Plan,'' consistent with the proposal to eliminate the requirement for the operator to submit an IOP for the reasons listed immediately below.

Removal of the IOP Requirement (§ 550.204)

The 2016 Arctic Exploratory Drilling Rule discussed how commenters generally criticized the IOP provision as being duplicative or redundant of existing requirements (see 81 FR at 46492–46493). In 2016, when the rule was adopted, BOEM disagreed with these commenters and published responses to the commenters in the preamble. In its responses, BOEM discussed how the IOP was distinct from existing regulations, the importance of contractor management as it related to the IOP provisions, and the BOEM Regional Director's ability to waive submission of required information in the EP that was already provided in the IOP. Circumstances have changed since the IOP requirement was originally adopted. The various Federal agencies have improved their coordination to such an extent that BOEM believes there is no need for operators to create and submit a separate IOP for that purpose. Much of the required content of the two documents overlaps, and in the 2016 rulemaking itself BOEM added requirements that the EP include additional information that made this overlap even greater. BOEM is now proposing to keep two important provisions from the IOP and incorporate them into the requirements for EPs. The first provision would reinforce BOEM's commitment to operational safety, while the second provision would require the operator to provide details of how its operations would conform to the unique circumstances of the Arctic OCS. Taken together, the enhancements to BOEM's regulations made in connection with the 2016 Arctic Exploratory Drilling Rule and the retention of these key provisions from the IOP make the IOP unnecessary and redundant.

For these reasons, BOEM proposes to eliminate the requirement for preparing and submitting the IOP. In doing so, BOEM would delete all of § 550.204, and remove corresponding references to the IOP from §§ 550.200 and 550.206. Currently, BOEM requires the operator to submit an IOP at least 90 days before filing an EP with BOEM. The IOP is not subject to agency approval. BOEM developed the IOP requirement based on the Report to the Secretary of the Interior, Review of Shell's 2012 Alaska Offshore Oil and Gas Exploration Program, prepared by DOI (60-Day Report), March 2013,[50] which included [51] the following recommendation:

> All phases of an offshore Arctic program—including preparations, drilling, maritime and emergency response operations—must be integrated and subject to strong operator management and government oversight. (60-day report, p. 3).

The information provided in the IOP was intended to facilitate the prompt sharing of information among the relevant Federal agencies (*e.g.,* BOEM, BSEE, USFWS, USCG, NMFS, U.S. Army Corps of Engineers, and EPA). Standing BOEM practice (LP–SOP–06 Standard Operating Procedure for Exploration Plans) in the Anchorage, Alaska OCS Office is to inform other agencies about an operator's EP, well in advance of the completeness review (*i.e.,* the deemed submitted determination) for the EP. BOEM successfully did so prior to the 2016 implementation of the IOP requirement.

The IOP requirement does not supersede or supplant the operator's obligation to comply with all other applicable Federal agency requirements. As described in the 2016 Arctic Exploratory Drilling Rule, the IOP process does not provide a mechanism for agencies to approve or disapprove the operator's proposed activities. BOEM has no authority under the IOP provision other than to make unenforceable suggestions to the operator. If BOEM or another agency determined that an operator was failing to engage in the needed integrated planning in advance of EP submission, BOEM could only compel an operator to do so through the EP review process.

The 2016 Arctic Exploratory Drilling Rule added informational requirements for EPs to address key concerns that motivated the IOP, as shown in Table 1, ''Crosswalk between the IOP provisions proposed for removal and existing EP regulations and review practices.'' Because this information is required in the EP, operators should be aware that they must plan for how they will manage contractors to reduce

[50] Available at: *https://www.doi.gov/sites/doi.gov/files/migrated/news/pressreleases/upload/Shell-report-3-8-13-Final.pdf.*

[51] Report to the Secretary of the Interior, Review of Shell's 2012 Alaska Offshore Oil and Gas Exploration Program, prepared by DOI (60-Day Report), March 2013, available at: *https://www.doi.gov/sites/doi.gov/files/migrated/news/pressreleases/upload/Shell-report-3-8-13-Final.pdf.*

operational risks and address the challenges associated with operations on the Arctic OCS. The EP regulations are clear that the operator must plan to coordinate the work of a number of contractors to ensure that time pressure, or other contractor complications, do not undermine safe and environmentally responsible operations. In particular, proposed § 550.220(c)(1) would require the operator to describe in the EP how it will design and conduct its exploratory drilling activities, and how it will manage and oversee these activities as an integrated endeavor. BOEM does not need, and nothing in OCSLA requires, an operator to inform Federal agencies about its planning on these issues in advance of an EP. The EP, however, will make evident whether the operator has done so, and if the EP does not address the operators' planning on all the required elements, BOEM will return the EP to the operator to include the requisite information in accordance with existing § 550.231(b).

As part of the 2016 Arctic Exploratory Drilling Rule, BOEM expanded the regulatory criteria for EPs to include information important for planning Arctic exploratory drilling. Specifically, BOEM expanded requirements for: Emergency plans at existing § 550.220(a), the EP's suitability for Arctic OCS conditions at proposed § 550.220(c)(1), ice and weather management at existing § 550.220(c)(2), SCCE capabilities at existing § 550.220(c)(3), deployment for a relief rig at proposed § 550.220(c)(4), resource-sharing at existing § 550.220(c)(5), and anticipated end of seasonal operation dates at existing § 550.220(c)(6).

BOEM's EP and environmental impact analysis (EIA) requirements at existing § 550.202, *What criteria must the Exploration Plan (EP), Development and Production Plan (DPP), or Development Operations Coordination Document (DOCD) meet?*, existing paragraphs (a) and (c) of § 550.211, *What must the EP include?*, existing paragraph (c) of § 550.216, *What biological, physical, and socioeconomic information must accompany the EP?*, existing paragraphs (a) and (b) of § 550.219, *What oil and hazardous substance spills information must accompany the EP?*, existing paragraphs (b), (c)(2) and (5) of § 550.220, *If I propose activities in the Alaska OCS Region, what planning information must accompany the EP?*, proposed paragraph (c)(1) of § 550.220, existing paragraph (a) of § 550.224, *What information on support vessels, offshore vehicles, and aircraft you will use must accompany the EP?*, and existing paragraph (b)(7) of § 550.227, *What environmental impact analysis (EIA) information must accompany the EP?* require the operator to address issues that the operator also needs to consider in preparing the IOP. The following table provides a detailed analysis of how the key operational provisions of the IOP are addressed in BOEM's existing regulations, and why the key safety provisions of the IOP will continue to be fully addressed by other provisions within BOEM's regulations:

TABLE 1—CROSSWALK BETWEEN THE IOP PROVISIONS PROPOSED FOR REMOVAL AND EXISTING EP REGULATIONS AND REVIEW PRACTICES

IOP provision	Coverage in BOEM's continuing regulations, operator EPs, and review practices
§ 550.204(a)—The operator describes how vessels and equipment were designed for Arctic OCS conditions;	§ 550.220 (c)(1)—The operator describes how drilling activities account for Arctic OCS conditions.
§ 550.204(b)—The operator includes a schedule of the exploratory program;	§ 550.211(a)—The operator includes a schedule and discussion of objectives for its exploration program.
§ 550.204(c)—The operator describes how its plans account for Arctic OCS conditions;	§ 550.220 (c)(1)—The operator describes how drilling activities account for Arctic OCS conditions. § 550.220(c)(2)—The operator describes weather and ice forecasting and management plans. § 550.224(a)—The operator describes vessels and aircraft it would use during exploration, including storage capacity of fuels. § 550.202—BOEM must review plans to ensure they are safe and do not cause undue or serious harm or damage to the human, marine, or coastal environment.
§ 550.204(d)—The operator describes general abandonment plans for wells;	§ 550.211(a)—The operator includes a schedule and discussion of objectives for its exploration program. § 550.220 (c)(1)—The operator describes how drilling activities account for Arctic OCS conditions. § 550.220(c)(2)—The operator describes weather and ice forecasting and management plans. § 550.220(c)(6)(ii) (proposed)—The operator would describe the termination of drilling operations consistent with the well control planning requirements under § 250.472 of this title.
§ 550.204(e)—The operator describes its plans for responding and managing ice hazards and weather events;	§ 550.220(c)(2)—The operator describes weather and ice forecasting and management plans. § 550.220(b)—The operator would describe critical operations and curtailment procedures.
§ 550.204(f)—The operator describes work to be performed by contractors;	§ 550.220 (c)(1)—The operator describes how drilling activities account for Arctic OCS conditions. § 550.220(c)(2)—The operator describes weather and ice forecasting and management plans. § 550.202—BOEM must review plans to ensure they are safe and do not cause undue or serious harm or damage to the human, marine, or coastal environment.
§ 550.204(g)—The operator describes how it will ensure operational safety;	§ 550.211(c)—The operator would describe the drilling unit, associated equipment, safety features, and storage of fuels and oils. § 550.220 (c)(1)—The operator describes how drilling activities account for Arctic OCS conditions.

TABLE 1—CROSSWALK BETWEEN THE IOP PROVISIONS PROPOSED FOR REMOVAL AND EXISTING EP REGULATIONS AND REVIEW PRACTICES—Continued

IOP provision	Coverage in BOEM's continuing regulations, operator EPs, and review practices
§ 550.204(h)—The operator describes oil spill response plans;	§ 550.219 (a) and § 550.219 (b)—The operator would describe its oil spill response plan and associated spill modeling report.
§ 550.204(i)—The operator describes efforts to minimize impacts to local community infrastructure;	§ 550.216 (c)—the operator must analyze socioeconomic resources associated with its exploratory program. § 550.227 (b)(7)—The operator must describe socioeconomic resources including employment and subsistence resources and harvest practices.
§ 550.204(j)—The operator describes how it could rely on local communities for parts of its exploratory drilling program.	§ 550.220 (c)(5)—The operator describes agreements it has with third parties in the event of an oil spill or emergency. § 550.219 (a) and § 550.219 (b)—The operator would describe its oil spill response plan and associated spill modeling report. § 550.227 (b)(7)—The operator must describe socioeconomic resources including employment and subsistence resources and harvest practices.

The following information that was previously required as part of the IOP submission, but not included in the EP requirements, is proposed to be added to the relevant sections of the EP:

Existing regulation text	New provision
§ 550.204(a)—The operator describes how vessels and equipment were designed for Arctic OCS conditions;	§ 550.220(c)(1)—The operator describes how the exploratory drilling (including vessels and equipment) would account for Arctic OCS conditions, including any allowances or limitations its vessels have from a classification society and/or the USCG.
§ 550.204(g)—The operator describes how it will ensure operational safety;	§ 550.211(b)—the operator describes how it will ensure operational safety.

To the extent that there is not an exact correlation between the information required in the IOP and that required in the EP, BOEM and BSEE believe that the additional information required in the IOP that is not in the EP is not necessary and certainly not necessary in advance of the EP.

Furthermore, the BOEM Anchorage, Alaska OCS Office meets with members of the Interagency Working Group on Alaska Energy Permitting and other relevant agencies, before an EP is submitted or deemed submitted. Although BOEM previously argued that the IOP would not delay, but in fact, speed development by encouraging earlier review and coordination between regulatory agencies, BOEM no longer believes that is the case. While it is true that the IOP might speed up BOEM's review and approval of an EP, by encouraging earlier review and coordination among agencies, such acceleration would not shorten the overall planning process undertaken by the operator to prepare and submit an EP. The operator should conduct the same degree of planning with or without an IOP, because such planning is necessitated by the EP requirements. The IOP merely shifts some of the agency review to earlier in the process. With or without a prescriptive requirement for an IOP, the operator's thorough advance planning and coordination between BOEM, the operator, and other agencies prior to submission, will result in fewer unexpected issues overall. In practice, the entire planning process from initial concept to actual drilling should be the same, with or without an IOP. What is more important in terms of timeline, is the detailed work the operator would conduct in preparing and submitting a well-crafted EP.

How do I submit the EP, DPP, or DOCD? (§ 550.206)

BOEM proposes to delete all references to the IOP in this section. The substantive provisions of this section that relate to EPs, DPPs, and DOCDs would remain unchanged.

What must the EP include? (§ 550.211)

BOEM proposes to move existing § 550.204(g) to § 550.211 as a new paragraph (b). All other provisions of § 550.211 would remain unchanged. The addition of the provision from § 550.204 into § 550.211 is designed to describe operational safety procedures that the operator has developed specific to conditions relevant on the Arctic OCS. These requirements were previously included in the IOP and not specifically enumerated as part of the requirements for an EP, although similar, more general requirements are already part of paragraphs (a), Description, objectives, and schedule, and (c), Drilling unit of this section. Paragraph (c) requires the operator to describe the drilling unit, associated equipment, safety features, and storage of fuels and oils.

Without the current IOP provisions, the applicant would already need to have the information required by this paragraph in order to comply with BSEE's regulations that currently require operators to develop, implement, and maintain a safety and environmental management system (SEMS) program (Subpart S, §§ 250.1900 to 250.1933), and as a result, moving this requirement from §§ 550.204 to 550.211 does not add any burden.

Retaining this important provision as part of the requirements for exploratory drilling on the Arctic OCS ensures consistency with the goals of this rulemaking and to better align BOEM's rules with those of BSEE. The following is a description of the provision that is being retained. The section describes how an operator will ensure operational safety while working in Arctic OCS conditions, including but not limited to:

(1) The safety principles that it intends to apply to itself and its contractors;

(2) The accountability structure within its organization for implementing such principles;

(3) How it will communicate such principles to its employees and contractors; and

(4) How it will determine successful implementation of such principles.

The text of this transferred regulation provision is identical to what it was in § 550.204(g). As such, this addition to § 550.211 will not impose any new burden on lessees or operators. BOEM believes that retaining this important safety and environmental protection is a necessary part of ensuring that energy exploration and development activity is safe and environmentally responsible.

If I propose activities in the Arctic OCS Region, what planning information must accompany the EP? (§ 550.220)

BOEM proposes to revise paragraphs (c)(1) and (4), and (c)(6)(ii) of § 550.220 to conform to BSEE's proposed changes to § 250.472, *What are the additional well control equipment or relief rig requirements for the Arctic OCS?*

Existing paragraph (c)(1) of § 550.220 would be revised to add text to account for the text in existing § 550.204(a), which would be removed. With the elimination of § 550.204, BOEM proposes to combine the requirements of these two sections into a revised § 550.220(c)(1) that would require the operator to describe how its exploratory drilling (including vessels and equipment) would account for Arctic OCS conditions, including any allowances or limitations its vessels have from a classification society and/or the USCG.

BOEM is proposing to add a new informational requirement for modified vessels. BOEM is seeking to confirm that the operator meets the requirements of other entities with authority over vessels, not to impose requirements on those vessels. Although this revised paragraph would appear to add new requirements, in fact this revision would simply clarify and formalize the existing arrangements between BOEM and these other entities. This provision is proposed in order to avoid any potential confusion that might otherwise arise regarding the incorporation of the existing IOP requirements into the EP and how they may relate to the regulations and jurisdiction of the United States Coast Guard, or the flag state of the vessel. According to this proposed revision, for vessel modifications, the operator would describe any approvals from the flag state and vessel classification society and include in that description any allowances or limitations placed upon the vessel by the classification society and/or USCG. Vessel modifications may include the suitability of vessels for Arctic conditions. These vessels may have or acquire classification from a ''recognized organization'' under the USCG's Alternative Compliance Program (ACP).[52] This specification provides the operator with guidance on what information the EP should contain to show that its vessels would be able to operate safely in the Arctic OCS. The specification would also show that BOEM is not duplicating regulations from USCG by acknowledging that the flag state, USCG, and/or the classification society have authority for approvals, allowances, and limitations placed upon modified vessels. For these reasons, this change would impose no material additional burden on lessee or operators beyond that which already exists and which has already been accounted for in the information collection burden for this section.

To ensure consistency with BSEE's proposed regulatory changes, BOEM is proposing to revise paragraphs (c)(4) and (c)(6)(ii) by requiring the operator to provide a general description of how they will comply with § 250.472, including a description of the termination of their operations. BSEE is proposing to revise § 250.472 to provide the operator with the option to either use an SSID or have access to a relief rig, as an additional means to secure the well in the event of a loss of well control, if the operator will be conducting exploratory drilling operations from a MODU.

III. Additional Comments Solicited

To assist BSEE and BOEM in these revisions, we are requesting public comments on specific issues discussed in the preamble. We will consider these comments while developing final regulations. To provide necessary context, we included the requests for public comments in appropriate locations throughout the preamble. For ease of commenting, we consolidated the requests for comments in this section of the preamble. While BSEE and BOEM are soliciting comment on specific topics associated with the proposed rule, the bureaus welcome the public to submit information or comment on any other topics relevant to this rulemaking that may not necessarily pertain to the bureaus' specific solicitation. At this stage, the bureaus are open to considering any option that would improve the regulatory changes proposed, including maintaining the original requirement as part of the final rule. In all cases, please provide supporting reasons and data for your responses.

(i) *Well Design When Using an SSID (§ 250.472(a))*—BSEE is seeking comments on how well design could be better addressed in this rulemaking to enhance the overall safety of operations on the Arctic OCS. More specifically, BSEE would like to know whether the well design requirement in proposed § 250.472(a) is adequate to address situations the operator may encounter if a well is shut-in with an SSID over an entire winter season (*e.g.,* six to nine months). These situations could include cases where the wellbore pressure profile may increase to reservoir pressures at the top of the well over the course of the winter season. BSEE would also like to know whether there are other scenarios that may occur in a shut-in well over the ice season.

(ii) *SSID Efficacy Relative to the Relief Rig and SSRW*—BSEE is proposing to revise the relief rig and SSRW requirement with the intent to minimize environmental damage due to a prolonged ongoing well control event. When drilling a relief well, there is a delay in stopping the uncontrolled flow of oil and other fluid into the marine environment while relief well drilling operations are taking place. When properly functioning as designed, there is usually no delay for operational use of an SSID compared to the process of utilizing the relief rig or capping stack. If the SSID does not initially function, the SSID may still be activated through the ROV intervention equipment and capabilities that BSEE is proposing as a SSID design requirement. The SSID would operate independently from the BOP. By having two independent, redundant components, as part of the well control system, the overall reliability and effectiveness of the entire system increases. BSEE would like to know of any cases or data, in addition to what we have already discussed in the preamble, regarding the performance and reliability of the SSID and its effectiveness compared to drilling a relief well.

(iii) NPC Report and Bratslavsky and SolstenXP Study—The NPC 2019 Report and the Bratslavsky and SolstenXP study have been valuable tools that were not available when promulgating the 2016 Arctic Exploratory Drilling Rule. BSEE requests the public to provide additional information or clarification related to those portions of these reports that the Bureau relied upon in this rulemaking.

(iv) *SSID Capability to Preserve Isolation Over the Winter Season (§ 250.472(a)(1)(iv))*—BSEE proposes to require that the SSID must be capable of

[52] 33 U.S.C. 3316 and 46 CFR part 8 implement the USCG's ACP.

preserving isolation through the winter season without solely relying on the elastomer elements of the rams (*e.g.,* by using a well cap) and allow re-entry during the following open-water season. BSEE understands that the operator is able to achieve long-term isolation by installing a well cap (*i.e.,* a metal-to-metal cap) on the SSID before leaving the device on the seafloor over the winter season. BSEE would like to know if there are means by which isolation would be preserved through the winter season in cases where a late-season emergency situation may not provide adequate time or ability to access the SSID to install a well cap.

(v) *SSID Dual Shear Requirement in Proposed § 250.472(a)(2)(i)*—The NPC 2019 Report describes the SSID used in the Kara Sea Project as having dual blind shear rams. BSEE does not propose requiring the SSID to be equipped with dual blind shear rams. However, BSEE is seeking comment on the advantages or disadvantages between dual blind shear rams and using dual shear rams, with ram locks, with one ram being a blind shear ram.

(vi) *SSID Redundant Control System Capabilities (§ 250.472(a)(2)(ii))*—BSEE proposes to require the SSID to use a redundant control system that includes ROV capabilities and a control station on the rig that is independent from the BOP control system. BSEE is contemplating whether it may be more appropriate to require the SSID's redundant control system capabilities to be separate from its ROV's capabilities, and to be consistent with the fully redundant control system requirements described in API Spec. 16D, *Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment,* Second Edition, July 2004, reaffirmed August 2013; incorporated by reference at § 250.198(e)(90); (*e.g.,* yellow pod and blue pod). In addition to meeting the ROV requirements in existing § 250.734(a)(5), BSEE is also considering whether there should be an additional manual method (separate from the redundant control system) to close the SSID's rams with the ROV and whether it may be appropriate to require a standby or tending vessel with an ROV. There could be cases where the SSID's control system on the drilling rig is not available (*e.g.,* due to failure or an evacuation of the rig).

(vii) *SSID Testing Requirements (§ 250.472(a)(5))*—BSEE is seeking comment on whether it is appropriate to align the SSID's proposed testing requirements with BSEE's existing BOP testing requirements in § 250.737, *What are the BOP system testing requirements?,* or whether there are more appropriate and reliable testing methods for SSIDs. BSEE would like to receive information on what testing procedures have been used in the past to test an SSID when it was deployed, or what testing procedures are being developed for future projects.

(viii) *Relief Rig Staging and Capping Stack Positioning Requirements*—BSEE proposes to revise the staging and positioning requirement for the relief rig and capping stack, respectively, by providing an opportunity to the operator to adjust the point in time during its operations when it must stage or position these pieces of equipment, from ''when drilling below or working below the surface casing'' to ''when drilling below or working below the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities.'' If the operator is able to demonstrate to BSEE that the operations it plans to conduct below the surface casing would not encounter any abnormally high-pressured or other geologic hazards before reaching the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities, then BSEE would allow the operator to delay staging of its relief rig or positioning of its SCCE until reaching that point. BSEE would like to know whether there are more appropriate criteria, other than ''abnormally high-pressured zones or other geologic hazards,'' that should be used to determine whether to allow the operator to delay positioning of the capping stack and relief rig. BSEE is also requesting comment on what types of information, other than what is listed in proposed § 250.471(a) and § 250.472 (b)—risk modeling data, off-set well data, analog data, and seismic data, could be used to demonstrate the absence of abnormally pressured zones or other geologic hazards, and how burden on the operator could change—increase or decrease—if BSEE were to require submission of that information in its APD.

(ix) *Alternative Regulatory Approach to the Relief Rig and Capping Stack Positioning Requirements*—BSEE is considering an alternative regulatory approach in which BSEE would revise the staging and positioning requirement for the relief rig and capping stack, respectively, by adjusting the point in time during its operations when it must stage or position these pieces of equipment, from ''when drilling below or working below the surface casing'' to ''when drilling below or working below the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities.'' However, there could be cases where the operator or BSEE may not have sufficient G&G or analogous well data on a proposed project to confidently identify the location of the first formation that the operator may encounter that is capable of flowing hydrocarbons in measurable quantities. BSEE is soliciting the public's comments about this regulatory approach. BSEE is also soliciting comment about the need for the operator to verify, on a case-by-case basis, zones not capable of flowing hydrocarbons in measurable quantities.

(x) *Installing and Operating an SSID in a Mudline Cellar*—BSEE is requesting more information about whether there are any operational or installation challenges the operator may encounter in attempting to operate the SSID when it is installed in a mudline cellar. In areas of ice scour, BSEE's current regulations at §§ 250.734(a)(13) and 250.738(h) require placement of subsea BOP systems in mudline cellars. In addition, proposed § 250.720(c)(2) requires placement of the wellhead in a mudline cellar in areas of ice scour. Proposed § 250.472(a)(4)(i) would require installation of the SSID below the BOP.

(xi) *Operating an SSID with a Subsea BOP Installed on the Seafloor*—Historically, drilling in the Beaufort Sea and the Chukchi Sea has occurred in waters less than 167 feet deep, and as recent as April 2020,[53] there were active leases in the Beaufort Sea where an SSID could have been deployed. If the operator installs all well control systems on the seafloor (subsea BOP systems and SSIDs), there could be as much as 128 feet of water column taken up by these systems and a ship's hull (if a drillship is used). BSEE would like to know what challenges operators could face in cases where there is little room to operate. BSEE would also like to know how operators addressed those challenges in the past, or how such challenges could be addressed in future operations.

(xii) *Fail-Safe Mechanisms Used on an SSID*—BSEE is seeking comment on what fail-safe mechanisms exist that could be applied to an SSID in cases where a subsea BOP system is used. BSEE is contemplating whether it may be necessary to require mechanisms, such as autoshear or deadman for the SSID, to address emergency situations, such as a sunken MODU, where the

[53] In April of 2020, the only leases with potential projects that would be subject to the Arctic OCS's SSID requirements were relinquished. However, there are other active leases in the Beaufort Sea located nearer to shore in shallower waters where exploration and development projects are actively being pursued (primarily through man-made gravel islands).

subsea BOP system may have failed and the SSID could no longer be functioned via the rig or ROV (due to lack of access). BSEE currently has fail-safe requirements for subsea BOP systems (autoshear and deadman systems), which could be applied to SSIDs. However, there could be unintended consequences from applying these fail-safe systems on an SSID when a subsea BOP system is used. BSEE is seeking comment on what fail-safe mechanisms could be deployed to address cases where the BOP fails and the SSID is inaccessible by an ROV or a MODU control station. If an autoshear system or a deadman system are appropriate fail-safe mechanisms, BSEE is seeking input on what criteria should be used to function these systems, to ensure they do not function at the wrong time or interfere with or impact the subsea BOP's autoshear and deadman systems.

(xiii) *Autoshear and Deadman System Requirements for Surface BOPs*—BSEE is contemplating establishing autoshear and deadman system requirements in cases where operators use a surface BOP. BSEE does not currently require the use of an autoshear or deadman system with surface BOPs. BSEE is seeking comment on what criteria should be established to function the autoshear or deadman systems in connection with a surface BOP. BSEE welcomes any other comments, unrelated to autoshear or deadman systems, which require additional consideration in those cases where a surface BOP is used.

(xiv) *Outcome-based Well Control System Requirements*—BSEE is seeking comment on other appropriate approaches to well-control operations in the Arctic. The NPC 2019 Report recommends accepting the use of an SSID in place of the requirement for SSRW capability. However, it also recommends replacing the relief rig and SSRW requirements with requirements that specify desired outcomes (*i.e.,* to stop the flow of a well and allow the operator to propose equivalent technology and demonstrate its capabilities). BSEE assumes that the NPC recommendation would entail a performance-based approach to the regulations, in which the operator could propose and demonstrate new technologies to meet a stated objective, rather than being required to use certain technologies, such as a relief rig.

(xv) *Suspension of Operations*—BSEE is considering the option of limiting the period during which a suspension would remain in effect to the period between one drilling season and the next when the operator is prevented from continuing its drilling or other leaseholding activities due to seasonal conditions. BSEE is seeking comment on this regulatory option for the new SOO provision it is proposing in a new paragraph (d) of § 250.175, or any other option that could avoid or minimize the additional burdens associated with making requests on an annual basis (if the duration of the suspension needs to be longer), but still assure diligent lease exploration and development.

(xvi) *Other Solicited Comments*—BSEE is also requesting comments on the specific costs and operational implications of each of the regulatory changes included in this proposed rule.

IV. Procedural Matters

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

Executive Order 12866 provides that the Office of Information and Regulatory Affairs (OIRA) within OMB will review all significant rules. This proposed action is an economically significant regulatory action that was submitted to OMB for review, as it would have an annual effect on the economy of $100 million or more. BSEE and BOEM developed an economic analysis to assess the anticipated costs and potential benefits of the proposed rule. Due to uncertainty surrounding the outcome of ongoing litigation regarding the availability of Arctic OCS planning areas for future leasing and energy development, BSEE and BOEM developed two baseline activity level forecasts: (1) Activity levels expected if the full Beaufort and Chukchi Sea planning areas are reopened (*i.e.,* the Full Arctic baseline), and (2) reduced activity levels if these areas remain withdrawn from leasing (*i.e.,* the Restricted Beaufort baseline). Under either scenario, the proposed action would be economically significant as a result of the estimated cost savings of this proposed rule. BSEE and BOEM estimate the amendments proposed in this rulemaking would provide annualized net benefits of $142 million under the Full Arctic baseline, or $121 million under the Restricted Beaufort baseline, discounted at 7 percent.

Details on the estimated cost savings of this proposed rule can be found in the rule's Initial Regulatory Impact Analysis (IRIA). The net quantified benefits for this proposed rule are based on cost savings less forgone benefits. The cost savings to both government and industry result from removing regulatory redundancies, reduction in paperwork burdens, provision for alternative methods of compliance, and adoption of improved industry technology. Forgone benefits result from slight increases in the risks to subsistence hunters and fishermen and wildlife stemming from an increased probability of small or catastrophic oil spills. The cost savings exceed the forgone benefits, leading to the net benefits summarized in the following paragraphs.

This proposed rule would revise regulatory provisions in 30 CFR part 250, subparts A, C, D, and G, and 30 CFR part 550, subpart B. BSEE and BOEM have reassessed a number of the provisions promulgated through the 2016 Arctic Exploratory Drilling Rule and are proposing to revise some provisions to reflect performance-based standards rather than prescriptive requirements. Other revisions remove redundant regulatory oversight provisions and provide regional flexibility in the administration of suspensions and associated lease term extensions, without significantly impacting the current levels of safety and environmental protection. The bureaus sought the best available data and information to analyze the economic impact of these changes. The IRIA for this rulemaking can be found in the *https://www.regulations.gov/* docket (Docket ID: BSEE–2019–0008).

BSEE and BOEM are proposing to revise certain regulations promulgated through the 2016 Arctic Exploratory Drilling Rule based on new information generated since the 2016 rule was finalized, and to support the goals of the Administration's regulatory reform initiatives, while ensuring safety and environmental protection. This proposed rule would revise certain existing regulations—§§ 250.105; 250.175; 250.198; 250.300(b); 250.470(b), (f), and (h); 250.471(a) and (b); 250.472(a), (b), and (c); 250.720(c); 550.200; 550.204; 550.206; 550.211; and 550.220(c). The bulk of the net benefits are derived from cost savings driven by a proposed revision to existing § 250.472(b) and (c), which is discussed below. The analysis suggests forgone benefits are small compared to the cost savings, and the primary forgone benefits are from possible impacts on the environment and subsistence hunting and whaling communities, that could be caused by an oil spill of greater duration and higher discharge volumes in the event the BOP, SSID, and capping stack were to fail in sequence, and a containment dome and flow system would be needed to capture oil flowing from the well while relief-well drilling operations are underway. These, and the other provisions, are discussed in greater detail within the IRIA.

The largest contributor to net benefits attributable to the proposed rule is the proposed revision to existing § 250.472 paragraphs (a), (b), and (c). As promulgated under the 2016 Arctic Exploratory Drilling Rule, this provision currently requires the use of a 'relief rig' and adoption of a 45-day shoulder season. The relief rig is a secondary drilling vessel that is available and capable of drilling an SSRW in the event of a loss of well control. The 45-day ''shoulder season'' was the maximum time permitted by the regulations to mobilize the relief rig to an incident, drill a relief well, kill and abandon the original well, and abandon the relief well prior to expected seasonal ice encroachment at the drill site. This shoulder season necessarily compresses the already short Arctic drilling timeframe and also limits the ability of operators to drill and complete a well in one season. The proposed revisions to § 250.472 would provide the operator with the option to either use an SSID or have access to a relief rig, as an additional means to secure the well in the event of a loss of well control, if the operator will be conducting exploratory drilling operations from a MODU. The two features of this flexibility driving the cost savings are the removal of the shoulder season and removal of the requirement for the secondary drilling vessel, if the operator elects to install an SSID to comply with § 250.472. Because of the relative cost effectiveness of procuring, and potential well control advantages of installing an SSID versus mobilizing a relief rig and the necessary support vessels and personnel, BSEE assumes operators will prefer this option when using MODUs. This proposed change would produce an annualized cost savings of $142 million under the Full Arctic baseline, or $121 million under the Restricted Beaufort baseline, discounted at 7%.

This proposed rule would reduce the burden imposed on industry, while maintaining safety and environmental protection. The forgone benefits of adopting the proposed rule include possible impacts on the environment, subsistence hunting and whaling communities, and an oil spill of greater duration with higher discharge volumes in the event a BOP and SSID were to fail. As discussed earlier in the preamble, BSEE proposes to require operators to operate an SSID independently from the BOP. By having two independent, redundant components (*i.e.,* the BOP and the SSID) as part of the well control system, the overall reliability and effectiveness of the entire system increases. In the event both devices were to fail, the capping stack would still be used as required in the permitted timeframe. When a capping stack is used to contain a well, the relief well can be drilled without an ongoing active spill event. If the capping stack were to fail, the containment dome and flow system would be used to capture the oil flowing from the well while relief-well drilling operations are underway.

Given that the proposed rule would remove the arrival timing requirement for these pieces of equipment, there may be a delay in their arrival, in comparison to the existing regulations. The amount of oil flowing from the well during that delayed period, would be the contributing factor to the proposed rule's forgone benefits. However, as discussed in the IRIA, the probability of a catastrophic spill event (as a result of the BOP and SSID systems experiencing total failures) is low. Coupled with a scenario in which a BOP, SSID, and capping stack were all to fail, the probability of realizing these forgone benefits may be even lower. Nonetheless, the possibility exists and if the BOP were to fail and the SSID were to function as designed, there would be no forgone benefits in comparison to the existing regulations (and there might be a gained benefit since the SSID would activate immediately).

As part of the final rule, BSEE and BOEM are contemplating the preparation of a sensitivity analysis for the Final RIA and are soliciting comments on ways to make the analysis as accurate as possible. The information we receive through public input on this proposed rule regarding the SSID's performance, reliability, and effectiveness may inform the preparation of a sensitivity analysis.

The timeframe of the present analysis is 24 years, composed of an initial 4 years with no activity followed by 20 years of activities beginning in 2024. The two tables below summarize BSEE's and BOEM's estimates of the total and annual net benefits derived from all proposed revisions and additions. Additional information on the time horizon, compliance costs, savings, benefits, and forgone benefits may be found in the IRIA published in the rule docket.

20-YEAR ESTIMATED ANNUALIZED NET BENEFITS ASSOCIATED WITH PROPOSED AMENDMENTS TO 30 CFR PART 250 SUBPARTS A, C, D, AND G, AND 30 CFR PART 550, SUBPART B UNDER FULL-ARCTIC BASELINE ASSUMPTIONS

Year (2024–2043)	Discounted to 2019 at 3%	Discounted to 2019 at 7%
Annualized (millions)	$149.8	$142.2

20-YEAR ESTIMATED ANNUALIZED NET BENEFITS ASSOCIATED WITH PROPOSED AMENDMENTS TO 30 CFR PART 250 SUBPARTS A, C, D, AND G, AND 30 CFR PART 550, SUBPART B UNDER RESTRICTED BEAUFORT BASELINE ASSUMPTIONS

Year (2024–2043)	Discounted to 2019 at 3%	Discounted to 2019 at 7%
Annualized (millions)	$126.0	$120.9

This proposed rule would revise multiple provisions in the current regulations to implement performance-based provisions based upon reasonably obtainable information on safety, technical, economic, and other issues. Redundant or unnecessary reporting requirements are also being eliminated. BSEE and BOEM are providing industry flexibility, when practical, to meet the safety or equipment standards, rather than specifying the compliance method. Based on a consideration of the qualitative and quantitative safety and environmental factors related to the rule, BSEE and BOEM determined that the proposed revisions would be consistent with the policies of the applicable E.O.s and the OCSLA.

Executive Order 13563 reaffirms the principles of E.O. 12866 while calling for improvements in the Nation's regulatory system to promote predictability, to reduce uncertainty, and to use the best, most innovative, and least burdensome tools for achieving regulatory ends. The E.O. directs agencies to consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the public where these approaches are relevant, feasible, and consistent with regulatory objectives. E.O. 13563 emphasizes that regulations must be based on the best available science and that the rulemaking process must allow for public participation and an open exchange of ideas. Furthermore, it promotes retrospective review of existing regulations that may be outmoded, ineffective, insufficient, or excessively burdensome. BSEE and BOEM have reviewed the existing regulations as amended by the 2016 Rule and have developed this proposed rule in a manner consistent with E.O. 13563.

Executive Order 13771 requires Federal agencies to take proactive measures to reduce the costs associated with complying with Federal regulations. This proposed rule is an E.O. 13771 deregulatory action.

B. Regulatory Flexibility Act and Small Business Regulatory Enforcement Fairness Act

The Regulatory Flexibility Act (RFA), 5 U.S.C. 601–612, requires agencies to analyze the economic impact of regulations when there is likely to be a significant economic impact on a substantial number of small entities and to consider regulatory alternatives that will achieve the agency's goals while minimizing the burden on small entities. The proposed rule would affect operators and Federal oil and gas lessees that could conduct exploratory drilling on the Arctic OCS. The RFA defines small entities as small businesses, small nonprofits, and small governmental jurisdictions. No small nonprofits or small governmental jurisdictions have been identified that would be impacted by this rule.

Businesses subject to this proposed rule fall under North American Industry Classification System (NAICS) codes 211111 (Crude Petroleum and Natural Gas Extraction) and 213111 (Drilling Oil and Gas Wells). For these classifications, a small business is defined as one with fewer than 1,250 employees (NAICS code 211111) and fewer than 1,000 employees (NAICS code 213111), respectively. A small entity is one that is ''independently owned and operated and which is not dominant in its field of operation.''

According to BOEM's list of Arctic OCS leaseholders, four businesses currently hold lease interests on the Arctic OCS. This proposed rule would directly affect all four Arctic lessees. Based on the small entity criterion, none of the four businesses are considered a small entity. No small companies hold leases on the Arctic OCS. Previously, a single small company with only one lease held acreage on the Arctic OCS. This company relinquished its lease in March 2016.

BSEE and BOEM prepared an Initial Regulatory Flexibility Analysis (IRFA), which can be found in Section VII of the IRIA. Given the challenging environment and associated costs of drilling in the Arctic OCS planning areas, no small entities are expected to operate in these areas for the foreseeable future. Therefore, BSEE and BOEM preliminarily conclude that no small entities would be affected by these proposed amendments, however the agency has prepared an IRFA and is seeking public comment on any small business impacts from the proposed amendments.

This proposed rule would meet the E.O. 12866 criteria for an economically significant rule because it would likely have an annual effect on the economy of $100 million or more in at least one year of the 20-year period analyzed, and BSEE/BOEM comply with the RFA and the Small Business Regulatory Enforcement Fairness Act by providing a regulatory flexibility analysis. The requirements would apply to all entities operating on the Arctic OCS regardless of company designation as a small business. For more information on the small business impacts, see the IRFA section in the IRIA. Small businesses may send comments on the actions of Federal employees who enforce, or otherwise determine compliance with, Federal regulations to the Small Business and Agriculture Regulatory Enforcement Ombudsman, and to the Regional Small Business Regulatory Fairness Board. The Ombudsman evaluates these actions annually and rates each agency's responsiveness to small business. If you wish to comment on actions by employees of BSEE or BOEM, call 1–888–REG–FAIR (1–888–734–3247).

C. Unfunded Mandates Reform Act of 1995 (UMRA)

This proposed rule would not impose an unfunded Federal mandate on State, local, or tribal governments and would not have a significant or unique effect on State, local, or tribal governments. The requirements in this proposed rule would apply to Arctic OCS oil and gas lessees and operators, not to State, local, and tribal governments. Thus, the proposed rule would not have disproportionate budgetary effects on these governments. BSEE and BOEM have determined the proposed changes in this rulemaking would result in cost savings annually to regulated entities. Therefore, a written statement under the Unfunded Mandates Reform Act (2 U.S.C. 1531 *et seq.*) is not required.

D. Takings Implication Assessment

Under the criteria in E.O. 12630, this proposed rule would not have significant takings implications. The proposed rule is not a governmental action capable of interference with constitutionally protected property rights. A Takings Implication Assessment is not required.

E. Federalism (E.O. 13132)

Under the criteria in E.O. 13132, this proposed rule would not have federalism implications. This proposed rule would not substantially and directly affect the relationship between the Federal and State Governments. To the extent that State and local governments have a role in OCS activities, this proposed rule would not affect that role. A Federalism Assessment is not required.

F. Civil Justice Reform (E.O. 12988)

This proposed rule complies with the requirements of E.O. 12988. Specifically, this rule:

1. Meets the criteria of section 3(a) requiring that all regulations be reviewed to eliminate errors and ambiguity and be written to minimize litigation; and

2. Meets the criteria of section 3(b)(2) requiring that all regulations be written in clear language and contain clear legal standards.

G. Consultation With Indian Tribes (E.O. 13175)

Under the criteria in E.O. 13175, Consultation and Coordination with Indian Tribal Governments (dated November 6, 2000), DOI's Policy on Consultation with Indian Tribes and Alaska Native Corporations (512 Departmental Manual 4, dated November 9, 2015), and DOI's Procedures for Consultation with Indian Tribes (512 Departmental Manual 5, dated November 9, 2015), we evaluated the subject matter of this rulemaking and determined that it would have tribal implications for Alaska Natives. As described earlier, future Arctic OCS exploratory drilling activities conducted pursuant to this proposed rule could affect Alaska Natives, particularly their ability to engage in subsistence and cultural activities. However, as discussed earlier in *Section I.*

Background, Subsection E. Partner Engagement in Preparation for This Proposed Rule, Item 2. Summary of Comments Received, BOEM's environmental studies program has provided nearly $500 million over the last 46 years to scientific research on the Alaska OCS, which includes the Arctic OCS. Since July 2016, BOEM has completed 35 environmental studies and has 23 ongoing studies that cover the Arctic, totaling nearly $72 million. While this proposed rule would change how operators could explore for OCS resources in the Arctic, there are ample opportunities to permit these activities consistent with ESA, MMPA, NEPA, and consultation with Alaska Native communities. BOEM's environmental studies program provides the information that is used to evaluate the potential environmental effects of leasing OCS lands for exploration and development and helps ensure BOEM and BSEE have the best science available for the public, industry, and federal permitting decisions.

In addition, Alaska Natives may also be beneficiaries of the proposed rule, to the extent they are partners in any exploratory activities. There are additional unquantified benefits in situations where a SSID is available to immediately shut-in a flowing well rather than waiting for a relief well to be drilled.

BSEE and BOEM are committed to regular and meaningful consultation and collaboration with Alaska Native Tribes and ANCSA Corporations on policy decisions that have tribal implications, including, as an initial step, through complete and consistent implementation of E.O. 13175, together with related orders, directives, and guidance. Therefore, BSEE and BOEM engaged in Government-to-Government tribal consultations, Government-to-ANCSA Corporations consultations, and meetings with municipal leaders (*i.e.,* mayors or their respective representatives), to discuss the subject matter of the proposed rule and solicit input in the development of the proposed rule.

On September 20, 2018, BSEE and BOEM began reaching out to leaders from Alaska Native Tribes, ANCSA Corporations, and municipalities to determine which partners were interested in having conversations with BSEE and BOEM about the rulemaking. Consultations entailed meetings in Alaska, at locations and times convenient to the Alaska Native communities and corporations, to ensure they can have proper representation during the meetings. Accordingly, the timing of these meetings was critical. BSEE and BOEM scheduled the meetings around important traditional subsistence and cultural activities, such as whaling, that take place during specific times of the year, particularly in the early fall. Between November 29, 2018 and January 30, 2019, BSEE and BOEM met with a majority of the tribal entities (23 of 25) originally invited to consult. The following table lists all 25 invited tribal entities, and the dates and locations of the meetings with the 23 entities.

Tribal entity name	Type of entity	Meeting date	Location
Native Village of Utqiagvik	Tribal Government	November 29, 2018	Anchorage.
Native Village of Wainwright	Tribal Government.		
Olgoonik Native Corporation	Native Corporation.		
Doyon Limited	Native Corporation.		
Arctic Slope Regional Corporation	Native Corporation	December 7, 2018.	
Native Village of Kotzebue	Tribal Government	December 10, 2018	Kotzebue.
Northwest Arctic Borough Mayor	Municipal Government.		
Native Village of Point Hope	Tribal Government	December 11, 2018	Point Hope.
Tikigaq Native Corporation	Native Corporation.		
Point Hope Mayor	Municipal Government.		
Alaska Eskimo Whaling Commission	Non-tribe that consults on tribe's behalf	December 13, 2018	Anchorage.
Cully Corporation	Native Corporation	December 14, 2018.	
North Slope Borough Mayor	Municipal Government	December 17, 2018	Utqiagvik.
City of Utqiagvik Mayor	Municipal Government.		
Native Village of Nuiqsut	Tribal Government	December 18, 2018	Nuiqsut.
Kuukpik Corporation	Native Corporation.		
Nuiqsut Mayor	Municipal Government.		
Inupiat Community of the Arctic Slope	Non-tribe that consults on tribe's behalf.		
Native Village of Kaktovik	Tribal Government	December 19, 2018	Kaktovik.
Kaktovik Inupiat Corporation	Native Corporation.		
Kaktovik Mayor	Municipal Government.		
Tanana Chiefs Conference	Tribal Government	December 20, 2018	Fairbanks.
Native Village of Point Lay	Tribal Government	January 30, 2019	Conference Call.
Kikiktagruk Corporation	Native Corporation	BSEE and BOEM made multiple attempts to contact these corporations. However, the bureaus did not receive a response from either organization.	
NANA Regional Corporation	Native Corporation.		

All Alaska Native input provided during the meetings was subsequently provided to DOI in writing and has been included in the administrative record for this proposed rule.

As previously discussed in part E of the background section in this preamble, BSEE and BOEM heard a variety of perspectives during their meetings with Alaska Natives. The most common comment received was a concern over food security. Subsistence resources, including bowhead and beluga whales, other marine mammals, fish, and birds, are a key food source for many people's diets in the native villages. Another common comment recommended inclusion of a requirement for an oil and gas operator to establish an agreement with those whaling communities potentially affected by a planned drilling project. Certain tribal representatives and most ANCSA corporations were supportive of this proposed rulemaking because it could help attract more economic opportunities to their villages. Other comments provided during the consultation meetings included a recommendation to provide broader outreach by presenting this rulemaking to the tribal assemblies and to citizens within the communities. One of the ANCSA corporations also recommended that this rulemaking take into account the NPC 2019 Report. Please refer to the discussions above in Part E (*Partner Engagement in Preparation for This Proposed Rule*) of the background section of this preamble for a description of how BSEE and BOEM are addressing this input during the rulemaking process. BSEE and BOEM intend to continue consultation with affected tribes and ANCSA Corporations following publication of this proposed rule.

H. Effects on Environmental Justice for Minority and Low-Income Populations (E.O. 12898)

E.O. 12898 requires Federal agencies to make achieving environmental justice part of their mission by identifying and addressing disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority and low-income populations. DOI has determined that this proposed rule would not have a disproportionately high or adverse human health or environmental effect on native, minority, or low-income communities because its provisions are designed to maintain environmental protection and minimize any impact of exploration drilling on subsistence activities and Alaska Native community resources and infrastructure.

I. Paperwork Reduction Act (PRA)

This proposed rule contains existing and new information collection (IC) requirements for both BSEE and BOEM regulations, and a submission to OMB for review under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*) is required. Therefore, each bureau will submit an IC request to OMB for review and approval. We may not conduct, or sponsor, and you are not required to respond to a collection of information unless it displays a currently valid OMB control number. OMB has previously reviewed and approved the existing information collection requirements associated with Outer Continental Shelf drilling permits, plans, and related information collection, which would be altered by this proposed rule. OMB has assigned the following OMB control numbers to the current ICs:

• 1014–0025 (BSEE), 30 CFR part 250, Applications for Permit to Drill (APD and revised APD) (expires 06/30/2023), and in accordance with 5 CFR 1320.10, an agency may continue to conduct or sponsor this collection of information while the renewal submission is pending at OMB.

• 1010–0151 (BOEM), 30 CFR part 550, subpart B Plans and Information (exp. 06/30/2021), and in accordance with 5 CFR 1320.10, an agency may continue to conduct or sponsor this collection of information while the renewal submission is pending at OMB.

The IC aspects affecting each bureau are discussed separately. Additionally, BOEM is seeking to renew these information collections for three years with this rulemaking. Instructions on how to comment follow those discussions.

The following table details proposed changes to the annual estimated hour burdens and non-hour costs; as well as associated wage cost changes for both BSEE and BOEM information submission activities described below:

BSEE

Requirement	Existing regulations		Proposed rule		Total changes		
	Number of responses	Number of burden hours	Number of responses	Number of burden hours	Change of responses	Change of burden hours	Changes in wage cost
Submit signed SSID and Well Design certification § 250.470(h)	0	0	2	6	+2	+6	+$848
Submit request to delay access to your SCCE—§ 250.471(a) and § 250.472(b)	0	0	2	2	+2	+2	+$286

There are no changes to non-hour costs for BSEE requirements.

BOEM

Requirement	Existing regulations		Proposed rule		Total changes		
	Number of responses	Number of burden hours	Number of responses	Number of burden hours	Change of responses	Change of burden hours	Changes in wage cost
Submit IOP, including all required information § 550.204	1	2,880	0	0	(1)	(2,880)	($316,800)
Submit required Arctic-specific information with EP § 550.220	1	350	1	400	....	+50	+5,500

There are no changes to non-hour costs for BOEM requirements.

BSEE Information Collection—30 CFR Part 250

The proposed regulations would establish new and/or revise current requirements and the submission of information for safe and environmentally responsible Arctic OCS oil and gas exploration in an APD. BSEE would use the information in our efforts to protect life and the environment, conserve natural resources, and prevent waste.

The following provides a breakdown of the paperwork and non-hour cost burdens for this proposed rule. For the current requirements retained in the proposed rule, we used OMB's approved estimated hour and non-hour cost burdens.

As discussed in the Preamble Section-by-Section above, and in the supporting statement available at *RegInfo.gov*, this proposed rule would modify language in §§ 250.175(d), 250.300(b), 250.470(f)(3), and 250.720(c)(2); however, there would be no change in hour burden or non-hour costs associated with these revisions.

In § 250.470(h), we would add a requirement to submit with an APD a certification signed by a registered professional engineer that your SSID and well design (including casing and cementing program) meet the design requirements in § 250.472 (+ 2 responses and 6 hours for PE Certification).

In §§ 250.471(a) and 250.472(b), we would add a requirement for operators to submit, with an APD, documentation demonstrating that having access to SCCE and the relief rig can be safely delayed until the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities. BSEE will grant this approval if the operator adequately demonstrates to the Bureau that it will not encounter any abnormally high-pressured zones or other geological hazards before that casing point (+ 2 responses and 2 hours per request).

Because not all APDs submitted to BSEE would involve Arctic OCS exploration drilling, we are separating the Arctic-specific requirements and burdens from the national APD requirements. The burden table below outlines the revised requirements and burdens associated with this proposed rulemaking.

Title of Collection: Revisions to the Requirements for Exploratory Drilling on the Arctic Outer Continental Shelf—Application for Permit to Drill (APD, Revised APD).

OMB Control Number: 1014–0025.

Form Number: BSEE–0123 (APD) and BSEE–0123S (Supplemental APD).

Type of Review: Revision of a currently approved collection.

Respondents/Affected Public: Potential respondents comprise Federal OCS oil, gas, and sulfur lessees/operators and holders of pipeline rights-of-way.

Total Estimated Number of Annual Respondents: Currently there are approximately 60 Oil and Gas Drilling and Production Operators in the OCS. Not all the potential respondents would submit information at any given time, and some may submit multiple times.

Total Estimated Number of Annual Responses: 11,331.

Estimated Completion Time per Response: Varies from 1 hour to 2,800 hours depending on activity.

Total Estimated Number of Annual Burden Hours: 77,945.

Respondent's Obligation: Most responses are mandatory, while others are required to obtain or retain benefits.

Frequency of Collection: Generally, on occasion and as required in the regulations.

Total Estimated Annual Nonhour Burden Cost: $4,400,470.

BURDEN TABLE

[Changes due to the proposed rule shown in **bold**]

Citation 30 CFR 250; application for permit to drill (APD)	Reporting or recordkeeping requirement *	Hour burden	Average number of responses	Annual burden hours (rounded)
		Non-hour cost burden		
Subparts A, C, D, E, G, H, P	Apply for permit to drill, sidetrack, bypass, or deepen a well submitted via Forms BSEE–0123 (APD) and BSEE–0123S (Supplemental APD). (This burden represents only the filling out of the forms, the requirements are listed separately below.).	1	190 applications	190
			$2,113 fee × 190 = $401,470	
Subparts D, E, G	Obtain approval to revise your drilling plan or change major drilling equipment by submitting a Revised APD and Supplemental APD [no cost recovery fee for Revised APDs]. (This burden represents only the filling out of the forms, the requirements are listed separately below.).	1	730 submittals	730
Subtotal			920 responses	920
			$401,470 non-hour cost burdens	
Subpart A				
125	Submit evidence of your fee for services receipt	Exempt under 5 CFR 1320.3(h)(1)		0
197	Written confidentiality agreement	Exempt under 5 CFR 1320.5(d)(2)		0
Subpart C				
300(b)(1), (2)	Obtain approval to add petroleum-based substance to drilling mud system or approval for method of disposal of drill cuttings, sand, & other well solids, including those containing Naturally Occurring Radioactive Material (NORM).	150	1 request	150
Subpart C subtotal			1 response	150

BURDEN TABLE—Continued

[Changes due to the proposed rule shown in **bold**]

Citation 30 CFR 250; application for permit to drill (APD)	Reporting or recordkeeping requirement *	Hour burden	Average number of responses	Annual burden hours (rounded)
	Subpart D			
408; 414(h)	Request approval of alternate procedures or equipment during drilling operations.	Burden covered under subpart A, 1014–0022		0
409	Request departure approval from the drilling requirements specified in this subpart; identify and discuss.	1	370 approvals	370
410(b); 417(b); 713	Reference well and site-specific information in case it is not approved in your Exploration Plan, Development and Production Plan, Development Operations Coordination Document. Burdens pertaining to EPs, DPPs, DOCDs are covered under BOEM 1010–0151.	8	1 submittal	8
410(d)	Submit to the District Manager: An original and two complete copies of APD and Supplemental APD; separate public information copy of forms per § 250.186.	0.5 R–0.5	380 submittals 380 submittals	190 190
411; 412	Submit plat showing location of the proposed well and all the plat requirements associated with this section.	2	380 submittals	760
411; 413; 414; 415; 420	Submit design criteria used and all description requirements; drilling prognosis with description of the procedures you will follow; and casing and cementing program requirements.	15	707 submittals	10,605
411; 416; 731	Submit diverter and BOP systems descriptions and all the regulatory requirements associated with this section.	11	380 submittals	4,180
411; 713	Provide information for using a MODU and all the regulatory requirements associated with this section.	10	682 submittals	6,820
411; 418	Additional information required when providing an APD include, but not limited to, rated capacities of drilling rig and equipment if not already on file; drilling fluids program, including weight materials; directional plot; H2S contingency plan; welding plan; and information we may require per requirements, etc.	20	380 submittals	7,600
414(c)	Request preapproval to use alternative equivalent downhole mud weight prior to submitting APD.	1	15 requests	15
420(a)(7)	Include signed registered professional engineer certification and related information.	3	1,034 certifications	3,102
423(c)	Submit for approval casing pressure test procedures and criteria. On casing seal assembly ensure proper installation of casing or liner (subsea BOP's only).	3	527 procedures & criteria.	1,581
428(b)	Submit to District Manager for approval revised casing setting depths or hole interval drilling depth; include certification by PE.	125	1 submittal	125
428(k)	Submit a description of the plan to use a valve(s) on the drive pipe during cementing operations for the conductor casing, surface casing, or liner.	125	1 submittal	125

BURDEN TABLE—Continued

[Changes due to the proposed rule shown in **bold**]

Citation 30 CFR 250; application for permit to drill (APD)	Reporting or recordkeeping requirement *	Hour burden	Average number of responses	Annual burden hours (rounded)
432	Request departure from diverter requirements; with discussion and receive approval.	8	53 requests	424
460(a)	Include your projected plans if well testing along with the required information.	17	2 plans	34
462(c)	Submit a description of your source control and containment capabilities to the Regional Supervisor and receive approval; all required information.	125	1 submittal	125
470(h)	**Submit certification signed by PE that SSID and well design meet requirements of § 250.472. (Alaska only)**.	**3**	**2 certs.**	**6**
471(a); 472(b)	**Submit, to Regional Supervisor, a request to delay access to your SCCE and relief rig, if applicable, including adequate documentation (such as, but not limited to, risk modeling data, off-set well data, analog data, seismic data). Demonstrate you will not encounter any abnormally high-pressured zones or other geologic hazards. (Alaska only)**.	**1**	**2 requests**	**2**
490(c)	Request to classify an area for the presence of H2S.	3	91 requests	273
	Support request with available information such as G&G data, well logs, formation tests, cores and analysis of formation fluids.	3	73 submittals	219
	Submit a request for reclassification of a zone when a different classification is needed.	1	4 requests	4
Alaska Region: 410; 412 thru 418; 420; 442; 444; 449; 456; **470; 471; 472**.	Due to the difficulties of drilling in Alaska, along with the shortened time window allowed for drilling, Alaska hours are done here as standalone requirements. Also, note that these specific hours are based on the first APD in Alaska in more than 10 years.	2,800	1 request	2,800
Subpart D subtotal			5,467 responses	39,558
	Subpart E			
513	Obtain written approval to begin well completion operations. If completion is planned and the data are available you may submit on forms.	3 R–3	288 requests 1 request	864 3
	Submit description of well-completion, schematics, logs, any H2S..	18.5 R–26	295 submittals 1 submittal	5,458 26
Subpart E subtotal			585 responses	6,351
	Subpart G			
701; 720	Identify and discuss your proposed alternate procedures or equipment.	Burden covered under subpart A, 1014–0022		0
702	Identify and discuss departure requests.	Burden covered under subpart A, 1014–0022		0
713(b)	Submit plat of the rig's anchor pattern for a moored rig approved in your EP, DPP, or DOCD.	125	1 submittal	125

BURDEN TABLE—Continued

[Changes due to the proposed rule shown in **bold**]

Citation 30 CFR 250; application for permit to drill (APD)	Reporting or recordkeeping requirement *	Hour burden	Average number of responses	Annual burden hours (rounded)
713(e)	Provide contingency plan for using dynamically positioned MODU and all the regulatory requirements associated with this section.	10	682 submittals	6,820
713(g)	Describe specific current speeds when implementing rig shutdown and/or move-off procedures for water depths > 400 meters; discussion of specific measures you will take to curtail rig operations/move-off location.	45	1 submittal	45
720(b)	Request approval to displace kill-weight fluid; include reasons why along with step-by-step procedures.	5	518 approval requests	2,590
721(g)(4)	Submit test procedures and criteria for a successful negative pressure test for approval. If any change, submit changes for approval.	2.5 R–4	355 submittals, 1 change.	8,884
731	Submit complete description of BOP system and components; schematic drawings; certification by ITP (additional I3P if BOP is subsea, in HPHT, or surface on floating facility); autoshear, deadman, EDS systems.	114	129 submittals	14,706
		$31,000 × 129 submittal = $3,999,000		
733(b)	Describe annulus monitoring plan; and how the well will be secured if leak is detected.	67	1 submittal	67
734(b)	Submit verification report from ITP documenting repairs and that BOP is fit for service.	R–64	1 report	64
734(c)	Submit revision, including all verifications required, before drilling out surface casing.	R–66	1 submittal	66
737(a)	Request approval from District Manager to omit BOP pressure test. Indicate which casing strings and liners meet the criteria for this request.	1	358 casing/liner info	358
737(b)(2)	Request approval of test pressures (RAM BOPs)	2	353 requests	706
737(b)(3)	Request approval of pressure test (annular BOPs).	2	380 requests	760
737(d)(2)	Submit test procedures for approval for surface BOP.	2.5	507 submittals	1,268
737(d)(3); (d)(4)	Submit test procedures, including how you will test each ROV intervention function, for approval (subsea BOPs only).	2	507 submittals	1,014
737(d)(12)	Submit test procedures (autoshear and deadman systems) for approval. Include documentation of the controls/circuitry system used for each test; describe how the ROV will be utilized during this operation.	2.5	507 submittals	1,268
738(b)	Submit a revised permit with a written statement from an independent third party documenting the repairs, replacement, or reconfiguration and certifying that the previous certification in § 250.731(c) remains valid.	.5	50 submittals	25
738(m)	Request approval to use additional well control equipment, including BAVO report; as well as other information required by District Manager.	66	1 request	66

BURDEN TABLE—Continued

[Changes due to the proposed rule shown in **bold**]

Citation 30 CFR 250; application for permit to drill (APD)	Reporting or recordkeeping requirement *	Hour burden	Average number of responses	Annual burden hours (rounded)
738(n)	Submit which pipe/variable bore rams have no current utility or well control purposes.	64	1 submittal	64
Subpart G subtotal			4,177 response	16,396
Subpart H				
807(a)	Submit detailed information that demonstrates the SSSVs and related equipment are capable of performing in HPHT.	13	1 submittal	13
Subpart H subtotal			1 response	13
Subpart P				
Note that for Sulfur Operations, while there may be 49 burden hours listed, we have not had any sulfur leases for numerous years, therefore, we have submitted minimal burden.				
1605(b)(3)	Submit information on the fitness of the drilling unit.	6	1 submittal	6
1617	Submit fully completed application (Form BSEE–0123) include rated capacities of the proposed drilling unit and of major drilling equipment; as well as all required information listed in this section.	40	1 submittal	40
1622(b)	Submit description of well-completion or workover procedures, schematic, and if H2S is present.	3	1 submittal	3
Subpart P subtotal			3 responses	49
Total Burden for APD			**11,331 Responses**	**77,945**
			$4,400,470 Non Hour Cost Burden	

* In the future, BSEE may require electronic filing of some submissions.

In addition, the PRA requires agencies to estimate the total annual reporting and recordkeeping non-hour cost burden resulting from the collection of information, and we solicit your comments on this item. For reporting and recordkeeping only, your response should split the cost estimate into two components: (1) Total capital and startup cost component and (2) annual operation, maintenance, and purchase of service component. Your estimates should consider the cost to generate, maintain, and disclose or provide the information. You should describe the methods you use to estimate major cost factors, including system and technology acquisition, expected useful life of capital equipment, discount rate(s), and the period over which you incur costs. Generally, your estimates should not include equipment or services purchased: (1) Before October 1, 1995; (2) to comply with requirements not associated with the information collection; (3) for reasons other than to provide information or keep records for the Government; or (4) as part of customary and usual business or private practices.

As part of our continuing effort to reduce paperwork and respondent burdens, we invite the public and other Federal agencies to comment on any aspect of this information collection, including:

(1) Whether the collection of information is necessary, including whether the information will have practical utility;

(2) The accuracy of our estimate of the burden for this collection of information;

(3) Ways to enhance the quality, utility, and clarity of the information to be collected; and

(4) Ways to minimize the burden of the collection of information on respondents.

Send your comments and suggestions on this information collection by the date indicated in the **DATES** section to the Desk Officer for the Department of the Interior at OMB–OIRA at (202) 395–5806 (fax) or via the *RegInfo.gov* portal (online). You may view the information collection request(s) at *http://www.reginfo.gov/public/do/PRAMain.* Please provide a copy of your comments to the BSEE Information Collection Clearance Officer (see the **ADDRESSES** section). You may contact Kye Mason, BSEE Information Collection Clearance Officer at (703) 787–1607 with any questions. Please reference Revisions to the Requirements for Exploratory Drilling on the Arctic Outer Continental Shelf (OMB Control No. 1014–0025), in your comments.

BOEM Information Collection—30 CFR Part 550

This proposed rule would add and remove requirements related to submitting exploration plans and other information before conducting oil and gas exploration drilling activities on the Arctic OCS. If final regulations become effective, the information collection burdens for this rulemaking would be consolidated into the existing collection for Subpart B, Control Number 1010–0151, and will be adjusted as necessary. BOEM is requesting OMB approve the modified collections of information for OMB Control Number 1010–0151 with the final rule publication.

Pertaining to this proposed rulemaking, BOEM would collect the information to ensure that planned operations will be safe; will not adversely affect the marine, coastal, or human environments; will respond to the special conditions on the Arctic OCS; and will conserve the resources of the Arctic OCS. BOEM would use the information to ensure, through advanced planning, that operators are capable of safely operating in the unique environmental conditions of the Arctic and to make informed decisions on whether to approve EPs as submitted or whether modifications are necessary.

BOEM proposes to remove the Integrated Operations Plan (IOP) regulations by deleting § 550.204 and removing the corresponding references to the IOP from §§ 550.200 and 550.206. BOEM's existing requirement to submit the IOP at least 90 days before the lessee or operator files an EP would be eliminated. The data and information requested in the IOP is largely unnecessary in light of the information already collected in the EP. The current approval for OMB Control Number 1010–0151 counts the similar burdens associated with IOPs and EPs in both. Therefore, BOEM would remove the burdens attributed to the IOPs, and keep the burdens attributed to EPs. Removing the IOP provision would decrease the annual burden hours by 1 response and 2,880 hours (- 1 response and 2,880 annual burden hours).

The proposed rule would add a requirement to § 550.211(b) to describe operational safety procedures that the operator has developed specific to conditions relevant on the Arctic OCS in the EP. These requirements were previously included in the IOP requirements that are removed from this rulemaking. Retaining this provision would lessen the 2,880-burden hour decrease by 50 annual burden hours (*i.e.,* by retaining 50 annual burden hours).

BOEM proposes to revise § 550.220(c)(1) to require a description of how exploratory drilling will be designed and conducted, including how all vessels and equipment will be designed, built, and/or modified, to account for Arctic OCS conditions and how such activities will be managed and overseen as an integrated endeavor, and in the description of vessel modifications, a description of any approvals from the flag state and the vessel classification society, including any allowances or limitations placed upon the vessel by the classification society and/or the USCG. Vessel modifications may include the suitability of vessels for Arctic conditions. These vessels may have or acquire classification from a ''recognized organization'' under the USCG's Alternative Compliance Program (ACP).[54] BOEM is seeking to confirm that the operator meets the requirements of other entities with authority over vessels, not to impose requirements on those vessels. BOEM believes that this change would not impose any material additional burdens on the lessees or operators. BOEM is also proposing to revise § 550.220(c)(4) and (6) by requiring the operator to provide a general description of how they will comply with § 250.472, including a description of the termination of their operations.

BOEM estimates that the proposed revisions would remove 2,880 annual burden hours that correlate to the removal of the existing IOP requirement. These changes would result in a net decrease of 2,830 annual burden hours.

Because not all EPs submitted to BOEM would involve Arctic OCS exploration drilling, we are separating the burden associated with the Arctic-specific requirements and burdens from the national EP requirements. The burden table that follows this paragraph outlines the revised requirements and burdens associated with this rulemaking. BOEM has not identified any non-hour cost burdens associated with these proposed requirements.

Title of Collection: Revisions to the Requirements for Exploratory Drilling on the Arctic Outer Continental Shelf—30 CFR part 550, subpart B, Plans and Information.

OMB Control Number: 1010–0151.

Form Number:

- BOEM–0137, OCS Plan Information Form
- BOEM–0138, EP Air Quality Screening Checklist
- BOEM–0139, DOCD/DPP Air Quality Screening Checklist.
- BOEM–0141, ROV Survey Report.
- BOEM–0142, Environmental Impact Analysis Worksheet.

Type of Review: Revision of a currently approved collection.

Respondents/Affected Public: Respondents are Federal oil and gas or sulfur lessees or operators.

Total Estimated Number of Annual Response: 4,265 respondents.

Total Estimated Number of Annual Burden Hours: 433,608 hours.

Respondent's Obligation: Some responses to the information collection are required to obtain or retain a benefit, and some are mandatory.

Frequency of Collection: The frequency of the response varies, but primarily responses are required only on occasion.

Total Estimated Annual Nonhour Burden Cost: $3,939,435.

BURDEN BREAKDOWN

[Current requirements in regular font; proposed *expanded requirements shown in italic font*]

Citation 30 CFR 550 subpart B and NTLs	Reporting & recordkeeping requirement	Hour burden	Average number of annual responses	Burden hours
		Non-hour costs		
200 thru 206	General requirements for plans and information; fees/refunds, etc.	Burden included with specific requirements below.		0
201 thru 206; 211 thru 228: 241 thru 262.	BOEM posts EPs/DPPs/DOCDs on FDMS and receives public comments in preparation of EAs.	Not considered IC as defined in 5 CFR 1320.3(h)(4).		0
Subtotal			0	0

[54] 33 U.S.C. 3316 and 46 CFR part 8 implement the USCG's ACP.

BURDEN BREAKDOWN—Continued

[Current requirements in regular font; proposed *expanded requirements shown in italic font*]

Citation 30 CFR 550 subpart B and NTLs	Reporting & recordkeeping requirement	Hour burden	Average number of annual responses	Burden hours
		Non-hour costs		
Ancillary Activities				
208; NTL 2009–G34 *	Notify BOEM in writing, and if required by the Regional Supervisor notify other users of the OCS before conducting ancillary activities.	11	61 notices	671
208; 210(a)	Submit report summarizing & analyzing data/information obtained or derived from ancillary activities.	2	61 reports	122
208; 210(b)	Retain ancillary activities data/information; upon request, submit to BOEM.	2	61 records	122
Subtotal			183 responses	91
Contents of Exploration Plans (EP)				
209; 231(b); 232(d); 234; 235; 281; 283; 284; 285; NTL 2015–N01.	Submit new, amended, modified, revised, or supplemental EP, or resubmit disapproved EP, including required information; withdraw an EP.	150	345 changed plans3	51,750
209; 211 thru 228; NTL 2015–N01.	Submit EP and all required information (including, but not limited to, submissions required by BOEM Forms 0137, 0138, 0142; lease stipulations; reports, including shallow hazards surveys, H2S, G&G, archaeological surveys & reports (§ 550.194) ***, in specified formats. Provide notifications.	600	163	97,800
		$3,673 × 163 EP surface locations = $598,699		
210; 220(a)–(c); 291; 292	*For existing Arctic OCS exploration activities: revise and resubmit Arctic-specific information, as required.*	700	1	700
202; 211; 216; 219, ***220(a)–(c);*** *224, 227;.*	*For new Arctic OCS exploration activities: submit required Arctic-specific information with EP.*	400	1	400
Subtotal			510 responses	150,650
			$598,699 Non-hour costs	
Review and Decision Process for the EP				
235(b); 272(b); 281(d)(3)(ii)	Appeal State's objection	Burden exempt as defined in 5 CFR 1320.4(a)(2), (c).		0
Contents of Development and Production Plans (DPP) and Development Operations Coordination Documents (DOCD)				
209; 266(b); 267(d); 272(a); 273; 281; 283; 284; 285; NTL 2015–N01.	Submit amended, modified, revised, or supplemental DPP or DOCD, including required information, or resubmit disapproved DPP or DOCD.	235	353 changed plans	82,955
241 thru 262; 209; NTL 2015–N01.	Submit DPP/DOCD and required/supporting information (including, but not limited to, submissions required by BOEM Forms 0137, 0139, 0142; lease stipulations; reports, including shallow hazards surveys, archaeological surveys & reports (§ 550.194)), in specified formats. Provide notification.	700	268	187,600
		$4,238 × 268 DPP/DOCD wells = $1,135,784.		
Subtotal			621 responses	270,555
			$1,135,784 Non-hour costs	

BURDEN BREAKDOWN—Continued

[Current requirements in regular font; proposed *expanded requirements shown in italic font*]

Citation 30 CFR 550 subpart B and NTLs	Reporting & recordkeeping requirement	Hour burden	Average number of annual responses	Burden hours
		Non-hour costs		
Review and Decision Process for the DPP or DOCD				
267(a)	Once BOEM deemed DPP/DOCD submitted; Governor of each affected State, local government official; etc., submit comments/recommendations.	Not considered IC as defined in 5 CFR 1320.3(h)(4).		0
267(b)	General public comments/recommendations submitted to BOEM regarding DPPs or DOCDs.	Not considered IC as defined in 5 CFR 1320.3(h)(4).		0
269(b)	For leases or units in vicinity of proposed development and production activities RD may require those lessees and operators to submit information on preliminary plans for their leases and units.	3	1 response	3
Subtotal			1 response	3
Post-Approval Requirements for the EP, DPP, and DOCD				
280(b)	In an emergency, request departure from your approved EP, DPP, or DOCD.	Burden included under 1010–0114.		0
281(a)	Submit various BSEE applications for approval and submit permits.	Burdens included under appropriate subpart or form (1014–0003; 1014–0011; 1014–0016; 1014–0018).		0
282	Retain monitoring data/information; upon request, make available to BOEM.	4	150 records	600
	Prepare and submit monitoring plan for approval	2	6 plans	12
282(b)	Prepare and submit monitoring reports and data (including BOEM Form 0141 used in GOMR).	3	12 reports	36
284(a)	Submit updated info on activities conducted under approved EP/DPP/DOCD.	4	56 updates	224
Subtotal			224 responses	872
Submit CIDs				
296(a); 297	Submit CID and required/supporting information; submit CID for supplemental DOCD or DPP.	375	14 documents	5,250
		$27,348 × 14 = $382,872		
296(b); 297	Submit a revised CID for approval	100	13 revisions	1,300
Subtotal			27 responses	6,550
			$382,872 Non-hour costs	
Seismic Survey Mitigation Measures and Protected Species Observer Program NTL				
NTL 2016–G02; 211 thru 228; 241 thru 262.	Submit to BOEM observer training requirement materials and information.	1.5 hours	2 sets of material	3
	Training certification and recordkeeping	1 hour	1 new trainee	1
	During seismic acquisition operations, submit daily observer reports semi-monthly.	1.5 hours	344 reports	516
	If used, submit to BOEM information on any passive acoustic monitoring system prior to placing it in service.	2 hours	6 submittals	12

BURDEN BREAKDOWN—Continued

[Current requirements in regular font; proposed *expanded requirements shown in italic font*]

Citation 30 CFR 550 subpart B and NTLs	Reporting & recordkeeping requirement	Hour burden	Average number of annual responses	Burden hours
		Non-hour costs		
	During seismic acquisition operations, submit to BOEM marine mammal observation report(s) semi-monthly or within 24 hours if air gun operations were shut down.	1.5 hours	1,976 reports	2,964
	During seismic acquisition operations, when air guns are being discharged, submit daily observer reports semi-monthly.	1.5 hours	344 reports	516
	Observation Duty (3 observers fulfilling an 8-hour shift each for 365 calendar days × 4 vessels = 35,040 man-hours). This requirement is contracted out; hence the non-hour cost burden.	3 observers × 8 hrs × 365 days = 8,760 hours × 4 vessels observing = 35,040 man-hours × $52/hr = $1,822,080.		
Subtotal			2,673 responses	4,012
			$1,822,080 Non-hour costs	
Vessel Strike Avoidance and Injured/Protected Species Reporting NTL				
NTL 2016–G01; 211 thru 228; 241 thru 262.	Notify BOEM within 24 hours of strike, when your vessel injures/kills a protected species (marine mammal/sea turtle).	1 hour	1 notice	1
Subtotal			1 response	1
General Departure				
200 thru 299	General departure and alternative compliance requests not specifically covered elsewhere in Subpart B regulations.	2	25 requests	50
Subtotal			25 responses	50
Total Burden			4,265 responses	433,608
			$3,939,435 Non-hour costs	

* The identification number of NTLs may change when NTLs are reissued periodically to update information.

In addition, the PRA requires agencies to estimate the total annual reporting and recordkeeping non-hour cost burden resulting from the collection of information, and we solicit your comments on this item. For reporting and recordkeeping only, your response should split the cost estimate into two components: (1) Total capital and startup cost component and (2) annual operation, maintenance, and purchase of service component. Your estimates should consider the cost to generate, maintain, and disclose or provide the information. You should describe the methods you use to estimate major cost factors, including system and technology acquisition, expected useful life of capital equipment, discount rate(s), and the period over which you incur costs. Generally, your estimates should not include equipment or services purchased: (1) Before October 1, 1995; (2) to comply with requirements not associated with the information collection; (3) for reasons other than to provide information or keep records for the Government; or (4) as part of customary and usual business or private practices.

As part of our continuing effort to reduce paperwork and respondent burdens, we invite the public and other Federal agencies to comment on any aspect of this information collection, including:

(1) Whether the collection of information is necessary, including whether the information will have practical utility;

(2) The accuracy of our estimate of the burden for this collection of information;

(3) Ways to enhance the quality, utility, and clarity of the information to be collected; and

(4) Ways to minimize the burden of the collection of information on respondents.

Send your comments and suggestions on this information collection by the date indicated in the **DATES** section to the Desk Officer for the Department of the Interior at OMB–OIRA at (202) 395–5806 (fax) or via the portal at RegInfo.gov (online). You may view the information collection request(s) at *http://www.reginfo.gov/public/do/PRAMain.* Please provide a copy of your comments to the BOEM Information Collection Clearance Officer (see the **ADDRESSES** section). You may contact Anna Atkinson, BOEM Information Collection Clearance Officer at (703) 787–1025 with any questions. Please reference Revisions to the Requirements for Exploratory Drilling on the Arctic Outer Continental Shelf (OMB Control No. 1014–0151), in your comments.

J. National Environmental Policy Act of 1969 (NEPA)

BSEE and BOEM developed a draft Environmental Assessment (EA) to determine whether this proposed rule would have a significant impact on the quality of the human environment under the NEPA. The draft EA is available for review in conjunction with this proposed rule at *www.regulations.gov* (in the Search box, enter BSEE–2019–0008).

K. Data Quality Act

In developing this proposed rule, we did not conduct or use a study, experiment, or survey requiring peer review under the Data Quality Act (44 U.S.C. 3516 note).

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

Although this proposed rule is a significant regulatory action under E.O. 12866, it is not a significant energy action under the definition of that term in E.O. 13211 because:

1. It is not likely to have a significant adverse effect on the supply, distribution or use of energy; and

2. It has not been designated as a significant energy action by the Administrator of OIRA.

Thus, a Statement of Energy Effects is not required.

While offshore Arctic OCS oil and gas studies indicate the potential of vast resources, there is currently little exploration activity and very little production of oil and gas on the Arctic OCS, largely due to the inherent practical difficulties of exploration and production in the area. The only existing oil production from the Arctic OCS is through the Northstar Island facility.

M. Clarity of Regulations

We are required by E.O. 12866, E.O. 12988, and by the Presidential Memorandum of June 1, 1998, to write all rules in plain language. This means that each rule we publish must:

1. Be logically organized;

2. Use the active voice to address readers directly;

3. Use clear language rather than jargon;

4. Be divided into short sections and sentences; and

5. Use lists and tables wherever possible.

If you believe we have not met these requirements, send us comments by one of the methods listed in the **ADDRESSES** section. To better help us revise the rule, your comments should be as specific as possible. For example, you should tell us the numbers of the sections or paragraphs that you find unclear, which sections or sentences are too long, or the sections where you believe lists or tables would be useful.

List of Subjects

30 CFR Part 250

Administrative practice and procedure, Continental shelf, Environmental impact statements, Environmental protection, Government contracts, Incorporation by reference, Investigations, Oil and gas exploration, Penalties, Pipelines, Public lands–mineral resources, Public lands—rights of-way, Reporting and recordkeeping requirements, Sulphur.

30 CFR Part 550

Administrative practice and procedure, Continental shelf, Environmental impact statements, Environmental protection, Mineral resources, Oil and gas exploration, Pipelines, Reporting and recordkeeping requirements, Sulfur.

Katharine MacGregor,

Deputy Secretary, U.S. Department of the Interior.

For the reasons stated in the preamble, BSEE and BOEM amend 30 CFR parts 250 and 550 as follows:

Title 30—Mineral Resources

CHAPTER II—BUREAU OF SAFETY AND ENVIRONMENTAL ENFORCEMENT, DEPARTMENT OF THE INTERIOR

SUBCHAPTER B—OFFSHORE

PART 250—OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF

■ 1. The authority citation for 30 CFR part 250 continues to read as follows:

Authority: 30 U.S.C. 1751, 31 U.S.C. 9701, 33 U.S.C. 1321(j)(1)(C), 43 U.S.C. 1334.

■ 2. Amend § 250.105 by revising the definition of ''Capping stack'' to read as follows:

§ 250.105 Definitions.

* * * * *

Capping stack means a mechanical device that can be installed on top of a subsea or surface wellhead or blowout preventer to stop the uncontrolled flow of fluids into the environment.

* * * * *

■ 3. Amend § 250.175 by adding paragraph (d) to read as follows:

§ 250.175 When may the Regional Supervisor grant an SOO?

* * * * *

(d) For leases or units on the Arctic OCS, you may request, and the Regional Supervisor may grant, an SOO when you have conducted leaseholding operations during the drilling season immediately preceding the period for which you are seeking a suspension, and you satisfy one of the following conditions:

(1) You are conducting drilling operations from a Mobile Offshore Drilling Unit (MODU), but you are not able to safely continue leaseholding operations due to the presence of seasonal ice;

(2) You are conducting drilling operations from an artificial gravel island or a gravity-based structure, but you are not able to safely continue leaseholding operations due to temporary seasonal restrictions in your approved oil spill response plan; or

(3) You are conducting drilling operations from an artificial ice island, but you are not able to safely continue leaseholding operations due to seasonal temperature changes.

■ 4. Amend § 250.198 by revising paragraph (e)(73) to read as follows:

§ 250.198 Documents incorporated by reference.

* * * * *

(e) * * *

(73) API RP 17H, Remotely Operated Tools and Interfaces on Subsea Production Systems, Second Edition, June 2013; Errata, January 2014; incorporated by reference at §§ 250.472(a) and 250.734(a);

* * * * *

■ 5. Amend § 250.300 by revising paragraphs (b)(1) and (2) to read as follows:

§ 250.300 Pollution prevention.

* * * * *

(b)(1) The District Manager may restrict the rate of drilling fluid discharges or prescribe alternative discharge methods. The District Manager may also restrict the use of components that could cause unreasonable degradation to the marine environment. No petroleum-based substances, including diesel fuel, may be added to the drilling mud system without prior approval of the District Manager. For Arctic OCS exploratory drilling, you must capture all petroleum-based mud to prevent its discharge into the marine environment.

(2) You must obtain approval from the District Manager of the method you plan to use to dispose of drill cuttings, sand, and other well solids. For Arctic OCS exploratory drilling, you must capture all cuttings from operations that use petroleum-based mud to prevent their discharge into the marine environment.

* * * * *

■ 6. Amend § 250.470 by:

■ a. Revising paragraphs (b)(11) and (12);

■ b. Adding paragraph (b)(13);

■ c. Revising paragraph (f)(3); and

■ d. Adding paragraph (h).

The revisions and additions read as follows:

§ 250.470 What additional information must I submit with my APD for Arctic OCS exploratory drilling operations?

* * * * *

(b) * * *

(11) Pick up the oil spill prevention booms and equipment;

(12) Offload the drilling crew; and

(13) Recover the subsea isolation device (SSID), where applicable.

* * * * *

(f) * * *

(3) Where applicable, proof of contracts or membership agreements with cooperatives, service providers, or other contractors who will provide you with the necessary SCCE or related supplies and services if you do not possess them. The contract or membership agreement must include provisions for ensuring the availability of the personnel and/or equipment on a 24-hour per day basis while you are drilling below or working below the surface casing, or before the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities, as approved by the Regional Supervisor.

* * * * *

(h) If you plan to install a subsea isolation device (SSID) on your well in accordance with § 250.472(a), a certification signed by a registered professional engineer that your SSID and well design (including casing and cementing program) meet the design requirements in § 250.472 and the design is appropriate for the purpose for which it is intended under expected wellbore conditions.

■ 7. Amend § 250.471 by revising paragraph (a) introductory text, and paragraphs (a)(2) and (3) and (b) to read as follows:

§ 250.471 What are the requirements for Arctic OCS source control and containment?

* * * * *

(a) If you use a MODU, you must have access to the SCCE as described in paragraphs (a)(1) through (3) of this section capable of controlling and containing the flow from an out-of-control well when drilling below or working below the surface casing. However, the Regional Supervisor will approve delaying access to your SCCE until your operations have reached the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities, provided that you submit adequate documentation (such as, but not limited to, risk modeling data, off-set well data, analog data, seismic data), with your APD, demonstrating that you will not encounter any abnormally high-pressured zones or other geologic hazards. The Regional Supervisor will base the determination on any documentation you provide as well as any other available data and information.

* * * * *

(2) A cap and flow system that can be deployed as directed by the Regional Supervisor pursuant to paragraph (h) of this section. The cap and flow system must be designed to capture at least the amount of hydrocarbons equivalent to the calculated worst case discharge rate referenced in your BOEM-approved EP; and

(3) A containment dome that can be deployed as directed by the Regional Supervisor pursuant to paragraph (h) of this section. The containment dome must have the capacity to pump fluids without relying on buoyancy.

(b) You must conduct a monthly stump test of dry-stored capping stacks.

* * * * *

■ 8. Revise § 250.472 to read as follows:

§ 250.472 What are the additional well control equipment or relief rig requirements for the Arctic OCS?

If you will be conducting exploratory drilling operations from a Mobile Offshore Drilling Unit (MODU), you must either use a Subsea Isolation Device (SSID) or have access to a relief rig as an additional means to secure the well in the event of a loss of well control. If you satisfy this requirement through use of an SSID, you must meet the requirements in paragraph (a) in this section. If you satisfy this requirement through maintaining access to a relief rig, you must meet the requirements in paragraph (b) in this section.

(a) *Subsea Isolation Device (SSID).* If you use an SSID to satisfy this requirement, your SSID and well (including the casing and cementing program) must be designed to achieve a full shut-in, without causing an underground blowout or having reservoir fluids broach to the seafloor. Your SSID must also meet the following requirements:

TABLE 1 TO PARAGRAPH (a)

Your SSID must	
(1) Be designed to:	(i) Close and seal the wellbore, independent of the BOP; (ii) Perform under the maximum environmental and operational conditions anticipated to occur at the well; (iii) Be left on the wellhead in the event the drilling rig is moved off location (*e.g.,* due to storms, ice incursions, or emergency situations); (iv) Preserve isolation through the winter season without relying on the elastomer elements of the rams (*e.g.,* by using a well cap) and allow re-entry during the following open-water season; and (v) In the event of a loss of well control, preserve isolation until other methods of well intervention may be completed, including the need to drill a relief well.
(2) Include the following equipment:	(i) Dual shear rams, including ram locks; one ram must be a blind shear ram; (ii) A redundant control system, independent from the BOP control system, that includes ROV capabilities and a control station on the rig; (iii) Independent, dedicated subsea accumulators with the capacity to function all components of the SSID; and (iv) Two side inlets for intervention; one inlet must be located below the lowest ram on the SSID.
(3) Include ROV intervention equipment and capabilities. Your ROV equipment and capabilities must:	(i) Be able to close each shear ram under MASP conditions, as defined for the operation; (ii) Include an ROV panel that is compliant with API RP 17H (as incorporated by reference in § 250.198); (iii) Meet the ROV requirements in § 250.734(a)(5); and (iv) Have the ability to function the SSID in any environment (*e.g.,* when in a mudline cellar).

TABLE 1 TO PARAGRAPH (a)—Continued

Your SSID must	
(4) Be installed:	(i) Below the BOP; (ii) At or before the time that you first install your BOP; and (iii) To provide protection from deep ice keels, in the event it must remain in place over the winter season (*e.g.,* installed in a mudline cellar).
(5) Be tested:	According to the BOP testing requirements in § 250.737.

(b) *Relief Rig.* If you choose to satisfy this requirement by having access to a relief rig, you must have access to your relief rig at all times when you are drilling below or working below the surface casing during Arctic OCS exploratory drilling operations. However, the Regional Supervisor will approve delaying access to your relief rig until your operations have reached the last casing point prior to penetrating a zone capable of flowing hydrocarbons in measurable quantities, provided that you submit adequate documentation (such as, but not limited to, risk modeling data, off-set well data, analog data, seismic data), with your APD, demonstrating that you will not encounter any abnormally high-pressured zones or other geologic hazards. The Regional Supervisor will base the determination on any documentation you provide as well as any other available data and information. Your relief rig must be different from your primary drilling rig, staged in a location, such that it would be available to arrive on site, drill a relief well, kill and abandon the original well, and abandon the relief well no later than 45 days after the loss of well control.

(1) Your relief rig must comply with all other requirements of this part pertaining to drill rig characteristics and capabilities, and it must be able to drill a relief well under anticipated Arctic OCS conditions.

(2) In the event of a loss of well control, the Regional Supervisor may direct you to drill a relief well using a relief rig that is able to kill and permanently plug an out-of-control well as described in your APD.

■ 9. Amend § 250.720 by revising paragraph (c)(2) to read as follows:

§ 250.720 When and how must I secure a well?

* * * * *

(c) * * *

(2) In areas of ice scour, you must use a well mudline cellar or an equivalent means of minimizing the risk of damage to the well head and wellbore. You may request, and the Regional Supervisor may approve, an alternate procedure or equipment in accordance with §§ 250.141 and 250.408.

* * * * *

CHAPTER V—BUREAU OF OCEAN ENERGY MANAGEMENT, DEPARTMENT OF THE INTERIOR

SUBCHAPTER B—OFFSHORE

PART 550—OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF

■ 10. The authority citation for 30 CFR part 550 continues to read as follows:

Authority: 30 U.S.C. 1751; 31 U.S.C. 9701; 43 U.S.C. 1334.

§ 550.220 [Amended]

■ 11. Amend § 550.200 by removing the words ''IOP means Integrated Operations Plan.'' in paragraph (a).

■ 12. Remove and reserve § 550.204.

§ 550.204 [Reserved]

■ 13. Amend § 550.206 by revising the section heading, paragraph (a) introductory text, and paragraphs (a)(3), (b), and (c) to read as follows:

§ 550.206 How do I submit the EP, DPP, or DOCD?

(a) *Number of copies.* When you submit an EP, DPP, or DOCD to BOEM, you must provide:

* * * * *

(3) Any additional copies that may be necessary to facilitate review of the EP, DPP, or DOCD by certain affected States and other reviewing entities.

(b) *Electronic submission.* You may submit part or all of your EP, DPP, or DOCD and its accompanying information electronically. If you prefer to submit your EP, DPP, or DOCD electronically, ask the Regional Supervisor for further guidance.

(c) *Withdrawal after submission.* You may withdraw your proposed EP, DPP, or DOCD at any time for any reason. Notify the appropriate BOEM Regional Office if you do.

■ 14. Amend § 550.211 by redesignating paragraphs (b) through (d) as paragraphs (c) through (e), respectively, and adding new paragraph (b) to read as follows:

§ 550.211 What must the EP include?

* * * * *

(b) A description of how you will ensure operational safety while working in Arctic OCS conditions, including but not limited to:

(1) The safety principles that you intend to apply to yourself and your contractors;

(2) The accountability structure within your organization for implementing such principles;

(3) How you will communicate such principles to your employees and contractors; and

(4) How you will determine successful implementation of such principles.

* * * * *

■ 15. Amend § 550.220 by revising the section heading, paragraphs (c)(1) and (4), and (c)(6)(ii) to read as follows:

§ 550.220 If I propose activities in the Arctic OCS Region, what planning information must accompany the EP?

* * * * *

(c) * * *

(1) A description of how your exploratory drilling will be designed and conducted, (including how all vessels and equipment will be designed, built, and/or modified) to account for Arctic OCS conditions and how such activities will be managed and overseen as an integrated endeavor. In your description of vessel modifications, describe any approvals from the flag state and the vessel classification society, including any allowances or limitations placed upon the vessel by the classification society and/or the United States Coast Guard.

* * * * *

(4) Additional well control equipment requirements for the Arctic OCS. A general description of how you will comply with § 250.472 of this title.

(6) * * *

(ii) The termination of drilling operations consistent with the well control planning requirements under § 250.472 of this title.

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