Approval Requirements for Activities That Involve the Use of a Subsea Blowout Preventer (BOP) or a Surface BOP On a Floating Facility

Purpose

The purpose of this document is to (a) summarize and clarify certain information relating to the regulations and guidance previously issued by the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), and (b) describe certain procedures being applied by BOEMRE's Gulf of Mexico OCS Region (GOMR), as they apply to previously-approved, pending, and newly-submitted Exploration Plans (EPs) and Development Operations Coordination Documents (DOCDs), Permits to Drill (APDs, RPDs, ASTs, RSTs, ABPs, RBPs, APMs, RPMs), and Regional Oil Spill Response Plans (OSRPs) regarding oil and gas activities in the Gulf of Mexico.

This document is intended to provide helpful information regarding the applicable requirements and procedures to obtain approval to conduct activities that propose using a drilling rig equipped with a subsea blowout preventer (BOP) system, a floating drilling rig equipped with a surface BOP system, or a drilling rig on a floating platform. The information contained in this document does not constitute new or additional regulatory requirements. Rather, this document is intended to provide lessees, operators and other relevant parties with information and clarity about the application and implementation of BOEMRE's existing regulations and guidance.

Background

Effective June 18, 2010, BOEMRE issued Notice to Lessees and Operators (NTL) No. 2010-N06, Information Requirements for Exploration Plans, Development and Production Plans, and Development Operations Coordination Documents on the OCS. The purpose of this NTL was to rescind the limitations set forth in NTL No. 2008-G04 regarding a blowout scenario and worst case discharge (WCD) scenario, and to provide national guidance to lessees and operators regarding the content of the information BOEMRE requires in blowout scenario and worst case discharge scenario descriptions.

On August 16, 2010, the Director of BOEMRE instructed the agency not to routinely use categorical exclusions with respect to National Environmental Policy Act (NEPA) reviews for EPs and DOCDs that propose to conduct an activity that requires approval of an APD and involves the use of a subsea BOP or a surface BOP on a floating facility. In light of this policy, BOEMRE describes in Appendix A of this document the information operators would need to supply to allow BOEMRE to prepare appropriate environmental assessments (EAs) for EPs and DOCDs for proposed operations that fall within these categories.

On October, 14, 2010, BOEMRE issued an interim final rule entitled "Increased Safety Measures for Energy Development on the Outer Continental Shelf" (75 FR 63346) (the Safety Interim Final Rule). The Safety Interim Final Rule implements certain safety measures recommended in the Department of the Interior's May 27, 2010, offshore energy safety report to the President. This rule amends drilling regulations related to well control, including regulations governing: subsea and surface BOP's, well casing and cementing, secondary intervention, unplanned disconnects, well completion, and well plugging.

Effective November 8, 2010, BOEMRE issued NTL No. 2010-N10, Statement of Compliance with Applicable Regulations and Evaluation of Information Demonstrating Adequate Spill Response and Well Containment Resources. This NTL directs operators to submit a statement, signed by an authorized company official, that the operator will conduct all authorized activities in compliance with all applicable regulations, including the Safety Interim Final Rule. This NTL also informed operators that BOEMRE will be evaluating whether they have submitted adequate information to demonstrate their ability to access and deploy containment resources that would be adequate to properly respond to a blowout or other loss of well control, in accordance with BOEMRE's existing regulations.

1. Regarding EPs or DOCDs:

See **Appendix A**, **Requirements for EPs and DOCDs.**

Revised EPs and DOCDs and Environmental Assessments

The clarifying guidance in Appendix A regarding the submission of information to be used in connection with an EA does not apply to EPs and DOCDs that propose to conduct the following activities:

a. drilling a relief well or intervention well for emergency purposes;
b. drilling a waterflood, gas injection, or a disposal well; or
c. drilling a sidetrack into a formation previously penetrated as long as the operator has complied with the information requirements in NTL No. 2010-N06.

Worst Case Discharge Calculations

Under our regulations, BOEMRE is responsible for ensuring that operators submit WCD calculations that determine the daily volume potential resulting from an uncontrolled blowout (*see* 30 CFR 254. 47(b)). BOEMRE has defined this as flow from all producible reservoirs into the open wellbore. The set of reservoirs exposed to an open borehole with the greatest discharge potential is considered the worst case discharge scenario.

BOEMRE has developed a consistent methodology for operators to use in calculating WCD and has provided guidance on the calculation of WCD in the form of responses to frequently asked questions regarding NTL No. 2010-N06 (http://www.gomr.boemre.gov/homepg/regulate/regs/ntls/2010NTLs/10-n06-FAQs.pdf). The purpose of this guidance has been to assist operators in complying with NTL No. 2010-N06 submission requirements. To ensure that operators understand the process and to provide transparency, BOEMRE staff is available to meet with individual operators to discuss their WCD calculations. These individual meetings allow for detailed discussion of specific projects and can include operator data that may be proprietary and, therefore, inappropriate to discuss in public documents or at meetings involving other companies. BOEMRE encourages operators to meet with our staff regarding WCD calculations, and we have found a high level of compliance among operators who have met with BOEMRE staff to discuss their WCD calculations.

BOEMRE's methodology for verifying operators' WCD calculations employs reservoir simulation and nodal analysis techniques routinely used in industry. BOEMRE does not require that operators use any prescribed methodology or software to calculate WCD. For example, operators have submitted and presented information on methodology and data used to calculate WCDs using various methodologies and software packages (including Merlin, Eclipse, WEB, Perform, Prosper, and Avalon), any of which is acceptable if done properly.

2. Regarding Well Permits:

To increase the safety of activities that require approval of an APD/RPD, an AST/RST, an ABP/RBP, or an APM/RPM operators must comply with the Safety Interim Final Rule.

See **Appendix B**, **Requirements under the Interim Final Rule**.

Operators must also provide the information set forth under NTL No. 2010-N10, Statement of Compliance with Applicable Regulations and Evaluation of Information Demonstrating Adequate Spill Response and Well Containment Resources, effective November 8, 2010.

If an operator's original APD, ABP, or AST has demonstrated that it has access to and can deploy containment resources that would be adequate to properly respond to a blowout or other loss of well control, then an RPD/RST/RBP for the same operation need not readdress the NTL No. 2010-N10 informational requirements, unless any of the elements of the operator's available containment resources has changed.

See **Appendix C, Requirements under NTL No. 2010-N10.**

3. Regarding OSRPs:

In accordance with 30 CFR 254.30 (e), BOEMRE's Regional Supervisor may require an operator to revise its OSRP if significant deficiencies in the OSRP are indicated by (1) periodic reviews of OSRO capabilities, (2) information obtained during drills or actual spill responses, or (3) other relevant information obtained by the Regional Supervisor, including, for example, changes in an operator's WCD calculation scenario as reflected in an operator's EP or DOCD submission. In the event that the BOEMRE Regional Supervisor requires an operator to revise its OSRP, the operator may continue to operate for up to two years while BOEMRE reviews the revised OSRP if the operator complies with 30 CFR 254.2(b), which requires that the operator certify that it has the capability to respond, to the maximum extent practicable, to a worst case discharge or substantial threat of such a discharge. This certification must establish that the operator has ensured by contract, or by other means approved by the Regional Supervisor, the availability of private personnel and equipment necessary to respond to the discharge. Confirmation from the organization(s) providing the personnel and equipment must accompany the certification.

During BOEMRE's review of revised OSRPs, BOEMRE will evaluate all available equipment, technologies, and practices addressing intervention and recovery, including, but not limited to, cap and collect, cap and contain, mechanical recovery, burning, dispersants (including subsea), and surveillance (including surveillance and operations at night, if equipment is available, e.g. Xband radar). While BOEMRE currently accepts the use of subsea dispersant, the Environmental Protection Agency has informed the Regional Response Team for Region VI that the use of subsea dispersants will be approved and monitored only on an incident specific basis. BOEMRE will also consider natural weathering, natural dispersion, subsea dispersant application, surface dispersant application, and in-situ burn capacity in evaluating and determining the adequacy of an operator's planned response to a worst case discharge.

BOEMRE expects operators to specifically address their planned response to each WCD identified in their OSRP. Operator response plans should consider factors including location, proximity to sensitive resources, event, volume, and product and should address appropriate source control, containment, weathering and natural dispersion, surface and subsea dispersion, in-situ burn, skimming and booming strategies specific to the event and response being analyzed.

To date, the primary deficiency that BOEMRE has identified in its review of OSRPs is the lack of sufficient subsea containment equipment and other resources. To address this deficiency, NTL No. 2010-N10 provides that an operator should submit information demonstrating that it has access to and can deploy containment resources that would be adequate to properly respond to a blowout or other loss of well control while conducting activities that require approval of an APD/RPD, AST/RST, or ABP/RBP and involve the use of a subsea BOP system, a floating drilling rig equipped with a surface BOP system, or a drilling rig on a floating platform. Operators may make this demonstration by, for example, submitting information in the form of a Containment Plan as part of its Regional or Subregional OSRP. Appendix C to this document describes information that operators should include in such a plan, as appropriate.

Operators are not required, at this time, to amend their OSRPs to include additional subsea containment information, but may do so voluntarily. With respect to the sufficiency of subsea containment resources, the types of information and resources that BOEMRE evaluates include, but is not limited to, the following, as applicable:

a. Worst case discharge scenario flow rate estimates
b. Offshore surface oil containment and recovery
c. Nearshore surface oil containment and recovery
d. Shoreline booming and protection strategies
e. Source abatement thru direct intervention
f. Relief wells
g. Debris removal from the site of a blowout, if necessary
h. Subsea containment and capture equipment, including containment domes and capping stacks. In the event that an operator proposes a capping stack as the single containment option, the operator should explain the reasons that the well design is sufficient to allow shut-in without broach to the sea floor.
i. Subsea utility equipment, including hydraulic power, hydrate control, and dispersant injection equipment
j. Riser systems
k. Remotely operated vehicles
l. Capture vessels
m. Support vessels
n. Storage facilities

o. Night operations
p. In-situ burn
q. Spotter aircraft
r. Responder communications equipment compatibility
s. Area Contingency Plan consistency

Regarding BOP tests

Operators are expected to notify BOEMRE at least 72 hours prior to all BOP stump tests and initial BOP tests on the seafloor to facilitate having a BOEMRE representative present to witness at least one of these tests. If BOEMRE receives appropriate notice and is unable to, or elects not to, witness at least one of the tests due to factors beyond the operator's control (including, for example, weather conditions and transportation availability), the operator may proceed with the test. However, in cases in which BOEMRE does not witness a BOP stump test or initial seafloor test, the operator must provide the results of the test (in either electronic or paper format) to BOEMRE within 72 hours of the test.

Contact

If you have any questions regarding the information requirements for EP's and DOCD's, contact Michael Tolbert of the BOEMRE GOMR Plans Section by telephone at (504) 736-2867 or by email at michael.tolbert@boemre.gov.

If you have any questions regarding the requirements for well permits, contact Jane Powers of the BOEMRE GOMR Office of Field Operations by telephone at (504) 736-2558 or by email at jane.powers@boemre.gov

If you have any questions regarding the requirements of NTL No. 2010-N10, contact Bryan Domangue of the BOEMRE GOMR Office of Field Operations by telephone at (985) 853-5885 or by email at bryan.domangue@boemre.gov

If you have any questions regarding the requirements for Regional and subregional OSRPs, contact Nick Wetzel of the BOEMRE GOMR Office of Field Operations by telephone at (504) 736-2419 or by email at nick.wetzel@boemre.gov

If you have any questions regarding BOP tests, contact Michael Saucier of the BOEMRE GOMR Office of Field Operations by telephone at (504) 736-2503 or by email at michael.saucier@boemre.gov.

APPENDIX A
Requirements for EPs and DOCDs

When an operator submits an initial EP or DOCD that involves activities that will require approval of an APD and involve the use of a drilling rig equipped with a subsea BOP system, a floating drilling rig equipped with a surface BOP system, or a drilling rig on a floating platform, the operator must include information specified in NTL No. 2008-G04, including the information described below for all EPs and DOCDs, and the information required by NTL No. 2010-N06.

When an operator submits a Supplemental EP or DOCD that involves activities that will require approval of an APD and involve the use of a drilling rig equipped with a subsea BOP system, a floating drilling rig equipped with a surface BOP system, or a drilling rig on a floating platform, the operator must include the following:

1. Information related to or affected by any proposed changes;
2. Any other pertinent information specified in NTL No. 2008-G04, including the information described below for EPs and DOCDs; and
3. Information required by NTL No. 2010-N06.

If an operator already has an approved EP or DOCD that involves activities that require approval of an APD and involve the use of a drilling rig equipped with a subsea BOP system, a floating drilling rig equipped with a surface BOP system, or a drilling rig on a floating platform, the operator must submit a revised EP or DOCD to BOEMRE for approval that includes the following before BOEMRE may approve any APDs under the previously-approved EP or DOCD:

1. Information related to or affected by proposed changes (if any);
2. Any other pertinent information specified in NTL No. 2008-G04, including the information described below for EPs and DOCDs; and
3. Information required by NTL No. 2010-N06.

In those cases where an operator is submitting a revised EP or DOCD only because an APD has been submitted for a well location previously approved under the plan, it is not necessary for the operator to submit a new or revised environmental impact analysis.

1. Plan Contents (30 CFR 250.211 and 250.241)

(a) Plan Information Form. Use Form MMS-137 to provide information concerning your proposed activities. For all Supplemental and Revised EP's and DOCD's, use Form MMS-137 to provide updated information on the description, objectives, and tentative schedule for all approved activities included in the EP or DOCD that have not yet been conducted. If applicable, indicate the approved activities that you have determined will never be conducted.

(b) Additional measures. Provide a discussion of the safety, pollution prevention, and early spill detection measures that you will take beyond those required by 30 CFR part 250.

2. General Information (30 CFR 250.213 and 250.243)

(a) Drilling fluids.

(1) Using the format below, provide information on the types (including chemical constituents) and amounts of the drilling fluids you plan to use to drill your proposed wells. Figures in the model tables below are included for illustrative purposes only.

Type of Drilling Fluid	Estimated Volume of Drilling Fluid to be Used per Well
Water-based (seawater, freshwater, barite)	35,000 bbls
Oil-based (diesel, mineral oil)	500 bbls
Synthetic-based (internal olefin, ester)	20,000 bbls

(2) For each oil-based drilling fluid you list in the table above,

(i) Use the format below to describe its major components:

Product Name	Amount to be Used	Reference Number
Bentonite	100 50-lb bags	CAS # 1302-78-9
PureDrill IA-35	500 bbls	CAS # 178603-63-9

(ii) Provide a Material Safety Data Sheet (MSDS), MSDS No., or Internet address for the MSDS (or equivalent information) for each product.

(b) Oils characteristics. For DOCDs only, use the format below to provide the chemical and physical characteristics of the oils (see definition under 30 CFR 254.6) that will be produced, handled, transported, or stored at the facilities you will use to conduct your proposed development and production activities.

Characteristic	Analytical Methodologies Should Be Consistent With:
(1) Gravity (API)	ASTM D4052
(2) Flash Point (°C)	ASTM D93/IP 34
(3) Pour Point (°C)	ASTM D97
(4) Viscosity (Centipoise at 25 °C)	ASTM D445
(5) Wax Content (wt %)	Precipitate with 2-butanon/dichloromethane (1 to 1 volume) at -10 °C
(6) Asphaltene Content (wt %)	IP-Method 143/84
(7) Resin Content (wt %)	Jokuty et al. (1996)
(8) Boiling point distribution including, for each fraction, the percent volume or weight and the boiling point range in degrees C	ASTM D2892 (TBP distillation), or ASTM D2887/5307
(9) Sulphur (wt %)	ASTM D4294

Note: For the distillation information in item no. 8 above, the BOEMRE GOMR may accept the following information in lieu of items nos. 5, 6, 7, and 8: weight percent total of saturates, aromatics, waxes, asphaltenes, and resins; and total BTEX (ppm) using analytical methods compatible with the Hydrocarbon Groups methodology from Jokuty et al. (1996).

Provide information on the oil composition most likely to result in the largest volume spill (e.g., the oil from the expected largest reservoir, stored oil or pipeline oil combined from a number of wells).

Identify the oil you analyze using one of the following formats:

Oil from one well	Oil from more than one well sampled on a facility	Oil from a pipeline system
Area/Block. BOEMRE platform ID. API Well No. Completion perforation interval BOEMRE reservoir name. Sample date. Sample No. (if more than one is taken).	Area/Block. BOEMRE platform ID. Field/Unit. Sample date. Sample No. (if more than one is taken). Listing of API Well Nos. Storage tank ID No. (if sampled at a storage tank.	Pipeline segment number. For each pipeline that feeds into the system, the ID codes for the closest upstream LACT units and/or facility measurement points. Storage tank ID No. (if sampled at a storage tank).

3. Waste and Discharge Information (30 CFR 250.217 and 250.248)

(a) Projected generated wastes. Using the format below, provide information on the projected solid and liquid wastes likely to be generated by your proposed activities. Include both operational wastes permitted by the appropriate NPDES permit and any other identified wastes.

Type of Waste	Composition	Projected Amount
Spent drilling fluids	Water-based drilling muds	8,000 bbls/well
Cuttings containing Synthetic-based mud	Cuttings coated with ester-based Synthetic drilling muds	600 bbls/well
Chemical product waste	Ethylene glycol Methanol	100 bbls/month 25 bbls/month
Trash	Refuse generated during painting operations	50 bbls/month

Describe also your plans for treating, storing, or downhole disposal of these wastes at your facility location(s).

(b) Projected ocean discharges. If any of your solid and liquid wastes are to be discharged overboard, use the format below to provide the following information.

Type of Waste	Total Amount to be Discharged	Discharge Rate	Discharge Method
Spent drilling fluids and cuttings containing synthetic-based mud	5,000 bbls	200 bbls/day	Shunt through downpipe to 40 feet above the mudline.
Chemical product wastes	50 bbls	2 bbls/day	Add to produced water stream.

(c) Modeling report. If you model the trajectory or fate of discharges of the projected solid or liquid wastes generated by your proposed activities, provide two copies of the modeling report or the modeling results, or a reference to such report or results if it has already been submitted to the Regional Supervisor. Include the oceanographic data you used in the modeling in the report. If you plan to model, consult with the Regional Supervisor for further guidance on preparing the modeling report. Provide this report only when you propose activities for which the U.S. Environmental Protection Agency requires an ***individual*** NPDES permit.

4. Oil Spills Information (30 CFR 250.219 and 250.250)

(a) Oil spill response discussion. Discuss your response to an oil spill resulting from the activities proposed in your EP or DOCD. Include all the information described in 30 CFR 254.26(b), (c), (d), and (e) that is applicable. As the source of the spill, use whichever of the following gives the greater volume of oil:

(i) The blow-out scenario you describe in the information you submit to comply with NTL No. 2010-N06; or

(ii) The volume of the largest oil/fuel storage tank on the drilling rig or facility.

(b) Modeling report. If you model a potential oil or hazardous substance spill, provide two copies of the modeling, or a reference to such a report if it has already been provided to the Regional Supervisor. Include the oceanographic data used in the modeling in the report. If you plan to model, contact the Regional Supervisor for guidance on preparing the report.

5. Support Vessels and Aircraft Information (30 CFR 250.224 and 250.257)

(a) Diesel oil supply vessels. Using the format below, provide additional information on the vessels you will use to supply diesel oil. Make sure you include any vessels that will transfer diesel oil you will use for purposes other than fuel (e.g., base for corrosion control fluids). If the specific fuel supply vessel has not yet been determined, use the maximum size, fuel capacity, and trip frequency for the type of vessel you will use.

Size of Fuel Supply Vessel	Capacity of Fuel Supply Vessel	Frequency of Fuel Transfers	Route Fuel Supply Vessel Will Take
180 feet	1,500 bbls	Weekly	From the shorebase in Fourchon, LA, to XYZ Field, then to WC Block 134.

(b) Solid and liquid wastes transportation. If you plan to transport any of your solid and liquid wastes from the site of your proposed activities to other offshore structures or to temporary or permanent onshore facilities for storage or disposal, use the format below to provide the following information:

Type of Waste Approx. Composition	Total Amount	Name/Location	Rate	Transport Method

Spent oil-based drilling fluids	1,000 bbls	XYZ Company, St. Mary, LA	200 bbls/day	Cuttings boxes on barges
Chemical product wastes	100 bbls	Mars Facility, Morgan City, LA	2 bbls/day 4 bbls/day	Drums on crew boat Drums on crew boat
Trash and debris	1,000 ft^3	Morgan City municipal landfill.	N/A	Storage bins on crew boat

6. Onshore Support Facilities Information (30 CFR 250.225 and 250.258)

(a) Support base construction or expansion timetable. If you plan to acquire land to construct or expand the onshore support base you will use, provide a timetable for land acquisition (including rights-of-way and easements) and construction or expansion.

7. Administrative Information (30 CFR 228 and 262)

Bibliography. If you refer to a previously submitted EP, DPP, or DOCD; study report; survey report; or other material in your EP or DOCD or its accompanying information, provide a list (with the BOEMRE GOMR control number, if known) of each referenced document. For Supplemental and Revised EPs and DOCDs, if the information has previously been submitted and provides all necessary and current information, refer to the plan control number of the EP or DOCD in which it was included for each section of the Supplemental or Revised plan (e.g., Plan Contents; General Information; Biological, Physical, and Socioeconomic Information; Air Emissions Information; etc.).

Appendix B
Requirements under the Safety Interim Final Rule

The requirements under this interim final rule are hereby clarified as follows:

A. Changes to API RP language (submitted under Subpart A)

1. Documents incorporated by reference located at 30 CFR 250.198(a)(3), are clarified as follows:

a. With respect to any incorporated document, the term "*should*", is to be interpreted as meaning "*must*" for purposes of these regulations. If this interpretation creates any contradictions or eliminates options available for addressing particular situations encountered by an operator, then an operator is to include, as part of its permit application, a discussion of the options that the operator considered and an explanation regarding the alternative chosen by the operator. Departures from the alternatives provided under the Safety Interim Final Rule will be evaluated on a case by case basis and granted where the situation warrants.

B. Applications for Permit to Drill (submitted under Subpart D)

1. Casing and Cementing Requirements located at 30 CFR 250.420(a)(6), are clarified as follows:

a. The registered professional engineer (PE) must certify that during the drilling/construction of the wellbore there will be two barriers in each annulus (for example, primary cement job and seal assembly) and that, upon running and cementing the final production casing/liner, there will be two barriers in the center of the wellbore (for example, dual mechanical floats). This certification may apply to a completion permit if you are running the production casing under the completion APM.
b. The PE may not certify work that was previously performed. The PE must only certify the work to be performed under the permit submitted.
c. When using less cement than approved in the original APD, an RPD will be required to include PE certification for the new cement volumes.
d. If an increase in cement volume is needed because an additional hydrocarbon zone is identified, then an RPD will be required to include PE certification for the new cement volumes.
e. As with other requests, requests for permit revisions outside normal business hours will require PE certification prior to approval. An email stating that the PE has certified the revisions will suffice, but the stamped revisions should be submitted within 72 hours of the e-mail to the appropriate District Office.
f. The barriers must be tested or in the case where a barrier cannot be tested there must be a methodology in place to verify the placement of the barrier (operational parameters or direct measurement methods that will indicate successful placement or successful installation.)

2. Casing and Cementing Requirements located at 30 CFR 250.415(f), are clarified as follows:

a. BOEMRE has developed an API RP 65 Part 2 compliance table for guidance. An operator may answer the questions in the table, along with the written descriptions where needed. If an operator supplies a written description in its own format, then the District Engineer will complete the table and answer the descriptions utilizing the information supplied by the operator. If the operator does not supply enough information to confirm compliance with standards of RP 65-Part 2 or any other provision under this subpart, then the permit application may be returned for clarification. (See attachment 1 for the table).

3. **Subsea BOP Verification Requirements located at 30 CFR 250.416(f),** are clarified as follows:

a. Regulations require that an independent third party verify that the subsea BOP stack has not been damaged or compromised from previous service. Because this verification cannot be performed until the BOP is pulled from the well where it is then-situtated, and then inspected and tested, this requirement may be addressed as a condition of approval. The condition will require an operator not to spud the well until it has submitted the independent third party verification stating that the BOP has been inspected and tested and that it has not been compromised or damaged from its previous service. This certification will be submitted in a RPD/RST prior to spudding the well.

4. **Pressure Testing Casing Requirements located at 30 CFR 250.423(c),** are clarified as follows:

a. For wells utilizing subsea stacks, a negative test is required for the intermediate and production casing strings. For wells utilizing surface stacks, all liner tops exposed in either the intermediate or production annulus will require a negative test. Any detection of flow or pressure build up will be considered a failed test.
b. In the event of a failed test, you must immediately investigate the cause, correct the problem, and notify the appropriate District Office. A procedure for the retest must be submitted and approved by the district.
c. For subsea wells, the negative test must be performed to the same degree of the expected pressure once the BOP is disconnected. For surface wells and liner tops, test to the highest differential pressure that is expected for the life of the well; at a minimum, the equivalent to 1 PPG less than pore pressure for that hole section.
d. The negative test must be performed prior to displacing the kill weight fluids with a lighter fluid.

5. **BOP Maintenance and Inspection Requirements located at 30 CFR 250.446(a)** are clarified as follows:

a. API RP 53, Section 17.10 states "After each well, the well control equipment should be cleaned, visually inspected, preventative maintenance performed, and pressure tested before installation on the next well." The pressure test may be performed after nippling up on the well for a surface stack.

6. BOP Inspection Requirements located at 30 CFR 250.451(i) is clarified as follows:

a. If pipe is sheared, either in a well control event or accidentally, you must retrieve, physically inspect, and conduct a full pressure test of the BOP stack.

C. Applications for Permit to Modify (submitted under Subparts E and F)

1. Well Completions, Re-completions and Workover Requirements located at 30 CFR 250.500 thru 30 CFR 250.618 are clarified as follows:

a. PE certification is not required when changing zones, plugging back for immediate sidetrack, or recompletions. PE certification is only needed for drilling, TA and PA permits.

2. BOP Maintenance and Inspection Requirements located at 30 CFR 250.516(g) and 30 CFR 250.617(l) are interpreted as follows:

a. API RP 53, Section 17.10 states "After each well, the well control equipment should be cleaned, visually inspected, preventative maintenance performed, and pressure tested before installation on the next well." The pressure test may be performed after nippling up on the well for a surface stack.

D. Applications for Permit to Modify (submitted under Subpart Q)

1. **Permanently Plugging Wells Requirements located at 30 CFR 250.1712(g),** are clarified as follows:

a. For wells being permanently abandoned (PA) and the wellhead removed, the PE needs to certify that there are two independent barriers in the center wellbore and the annuli are isolated per the regulations at 30 CFR 250.1715. However, if the wellhead is being left in place for the PA, the PE must certify two independent barriers in both the center wellbore and the annuli.
b. The PE may not certify work that was previously performed, the PE must only certify the work to be performed under the permit submitted.
c. PE certification is not required for an APM to conduct work that would convert a temporarily abandoned (TA) well to a PA well by cutting and pulling casings only (assuming that there are no additional plugs being set and there are no cementing operations taking place.)
d. As with other requests, requests for permit revisions outside normal business hours will require PE certification prior to approval. An email stating that the PE has certified the revisions will suffice, but the stamped revisions should be submitted within 72 hours of the e-mail to the appropriate District Office.
e. The barriers must be tested or in the case where a barrier cannot be tested, there must be a methodology in place to verify the placement of the barrier (operational parameters or direct measurement methods that will indicate successful placement or successful installation.)

2. **Temporary Plugging of Wells Requirements located at 30 CFR 250.1721 thru 30 CFR 250.1723** are clarified as follows:

   a. PE certification is required for a "partial" TA; these are conducted for "idle iron" wells when setting a downhole zonal isolation plug.
   b. The PE may not certify work that was previously performed. The PE must only certify the work to be performed under the permit submitted.
   c. Requests for permit revisions outside normal business hours will require PE certification prior to approval. An email stating that the PE has certified the revisions will suffice, however the stamped revisions must be submitted within 72 hours to the appropriate District Office.
   d. 30 CFR 250.1721(h) requires the PE to certify that the well will be left with two independent barriers in the center wellbore and the annuli.
   e. The barriers required by 30 CFR 250.1721(h) must be tested, or in the case where a barrier cannot be tested, there must be a methodology in place to verify the placement of the barrier (operational parameters or direct measurement methods that will indicate successful placement or successful installation.)

Regulatory Requirement: §250.415(f) A written description of how an operator evaluated the best practices included in API RP 65-Part 2, Isolating Potential Flow Zones During Well Construction (incorporated by reference as specified in §250.198). An operator's written description must identify the mechanical barriers and cementing practices it will use for each casing string (reference API RP 65-Part 2, Sections 3 and 4).

The following questions are listed to provide guidance on how to comply with the written description required in 30 CFR 250.415(f). An operator may answer the questions in the table, along with the written descriptions where needed. If an operator supplies a written description in its own format, then the BOEMRE District Engineer will use the table below and answer the questions utilizing the information the operator supplied. If the operator does not supply enough information to confirm compliance with the requirements of RP 65-Part 2 and any other provisions required under this subpart, the District Engineer may return the permit application for clarification.

	GENERAL QUESTIONS:	
1	Have you considered the following in your well planning and drilling plan determinations: evaluation for flow potential, site selection, shallow hazards, deeper hazard contingency planning, well control planning for fluid influxes, planning for lost circulation control, regulatory issues and communications plans, planning the well, pore pressure, fracture gradient, mud weight, casing plan, cementing plan, drilling plan, wellbore hydraulics, wellbore cleaning, barrier design, and contingency planning? [API 65-2 1.5]	Yes/No
2	Have you considered the general well practices while drilling, monitoring and maintaining wellbore stability, curing and preventing lost circulation, and planning and operational considerations? [API 65-2 1.6]	Yes/No
	FLOW POTENTIAL	
3	Will a pre-spud hazard assessment be conducted for the proposed well site?	Yes/No
4	List all potential flow zones within the well section to be cemented.	Describe below
5	Has the information concerning the type, location, and likelihood of potential flow zones been communicated to key parties (cementing service provider, rig contractor, or 3rd parties)?	Yes/No
	CRITICAL DRILLING FLUID PARAMETERS	

6	Are fluid densities sufficient to maintain well control without inducing lost circulation?	Yes/No
	CRITICAL WELL DESIGN PARAMETERS	
7	Will you use a cementing simulation model in the design of this well?	Yes/No
7a	If yes, how is the output of this simulation model used in your decision-making process?	Describe below
7b	If no, include discussion of why a model is not being used.	Describe below
7c	Either way, include the number and placement of centralizers being used.	Describe below
8	Will you ensure the planned top of cement will be 500 feet above the shallowest potential flow zone?	Yes/No
9	Have you confirmed that the hole diameter is sufficient to provide adequate centralization?	Yes/No
10	If there are any isolated annuli, how have you mitigated thermal casing pressure build-up?	NA or Describe below
11	Will you ensure the well will be stable (no volume gain or losses, drilling fluid density equal in vs. out) before commencing cementing operations?	Yes/No
12	List all annular mechanical barriers in your design.	Describe below
13	Has the rathole length been minimized or filled with drilling fluid with a density greater than the cement density?	Yes/No
14a	If you have any liner top packers exposed to the production or intermediate annulus, what is the rating for differential pressure across this packer?	NA or Describe below
14b	If you have any liner top packers exposed to the production or intermediate annulus, have you confirmed that your negative test will not exceed this rating?	Yes/No/NA
15	What type of casing hanger lock-down mechanisms will be used?	Describe below
16	For all intermediate and production casing hangers set in subsea, HP wellhead housing, will you immediately set/energize the lock-down ring prior to performing any negative test?	Yes/No
17	For all production casing hangers set in subsea, HP wellhead housing, will you set/energize the lock-down sleeve immediately after running the casing and prior to performing any negative test?	Yes/No
	CRITICAL OPERATIONAL PARAMETERS	
18	Will you have 2 mechanical barriers in addition to cement in your final casing string (or liner if it is your final string)?	Yes/No
19	Do you plan to nipple down BOP in accordance with the WOC requirements in 30 CFR 250.422 and API RP 65 Part 2 First Edition?	Yes/No
20	Do you plan on running a cement bond log on the production and intermediate casing/liner prior to conducting the negative test on that string?	Yes/No
	Are contingency plans in place for the following:	
21	Lost circulation?	Yes/No
22	Unplanned shut-down?	Yes/No
23	Unplanned rate change?	Yes/No
24	Float equipment does not hold differential pressures?	Yes/No
25	Surface Equipment issues?	Yes/No
26	Will you monitor the annulus during cementing and WOC time?	Yes/No
27	If using foam cement, is a risk assessment being conducted and incorporated into cementing plan?	Yes/No
28	If using foam cement, will the foamer, stabilizer, and nitrogen injection be controlled by an automated process system?	Yes/No
	CRITICAL MUD REMOVAL PARAMETERS	
28	Have you tested your drilling fluid and cementing fluid programs for compatibility to reduce possible contamination?	Yes/No
29	Have you considered actual well conditions when determining appropriate cement volumes?	Yes/No
30	Has the spacer been modeled or designed to achieve the best possible mud removal?	Yes/No
	CRITICAL CEMENT SLURRY PARAMETERS	
31	Have all appropriate cement slurry parameters been considered to ensure the highest probability of isolating all potential flow zones?	Yes/No
32	Do you plan on circulating bottom up prior to the start of the cement job?	Yes/No

If any question is answered "No," additional explanation will be needed as to why that practice is not being followed; identify the question and provide that explanation below. The following questions always require a description (if not applicable, state "Not Applicable"): Nos. 4, 7a, 7b, 7c, 10a, 12, 14a, 15.

Appendix C
Requirements under NTL No. 2010-N10

A. In order to ensure that an operator can safely conduct activities that require approval of an APD/RPD, an AST/RST, or an ABP/RBP, and involve the use of a subsea BOP system, a floating drilling rig equipped with a surface BOP system, or a drilling rig on a floating platform, the operator must provide a statement of compliance in accordance with NTL No. 2010-N10. This statement of compliance must be provided with each APD/RPD, AST/RST, or ABP/RBP in the categories described above and must be signed by the company's authorized official that is on file with BOEMRE.

B. For activities that require approval of an APD/RPD, an AST/RST, or an ABP/RBP and involve the use of a subsea BOP system, a floating drilling rig equipped with a surface BOP system, or a drilling rig on a floating platform, BOEMRE will evaluate whether an operator has submitted adequate information demonstrating that it has access to and can deploy surface and subsea containment resources that would be adequate to promptly respond to a blowout or other loss of well control.

   An operator may satisfy these informational requirements by, for example, submitting a Containment Plan as part of its regional or subregional OSRP. This Containment Plan should demonstrate that the operator has access to and can deploy containment resources that would be adequate to properly respond to a blowout or other loss of well control.

   In evaluating the sufficiency of subsea containment information submitted by an operator, BOEMRE will consider an analysis of the Mudline Shut-In Pressure (MLSIP) for the proposed operation. This analysis will consist of an evaluation of the well design to determine MLSIP (that is, the pressure that the system at the mudline would have to contain.) BOEMRE will evaluate whether the operator has demonstrated the ability to shut in the well with a capping stack with full displacement of the mud while maintaining wellbore integrity (including, e.g., casing, shoe, and open hole) under MLSIP. In cases in which an operator proposes a capping stack as the primary containment option, BOEMRE will evaluate whether the well design is sufficient to allow shut-in without broach to the sea floor. If full containment is necessary, BOEMRE will evaluate the process flow for the entire containment system, including source to storage of captured oil. BOEMRE also will evaluate factors such as debris removal from the site of a blowout, if required. This analysis will not be performed with respect to proposed operations under APM's or RPM's.

<u>GUIDELINES FOR THE DEVELOPMENT OF CONTAINMENT PLANS</u>

Make the following assumptions:

1. An uncontrolled Blowout/Explosion/Fire scenario that requires evacuation of the rig/facility.
2. Full displacement of drilling fluid

Address the following:

1. **Debris Removal**
   Assuming that an evacuated facility or rig has suffered a blowout, explosion, and/or a fire causing it to topple, evaluate your ability to regain vertical access to the blowout well. Provide a description of all available equipment to perform debris removal specific to this scenario.
2. **Subsea containment and capture equipment, including containment domes and capping stacks**
3. **Subsea utility equipment, including hydraulic power, hydrate control, and dispersant injection equipment**.
4. **Riser systems.**
5. **Remotely Operated vehicles (ROVs)**
6. **Capture vessels.**
7. **Support vessels.**
8. **Storage facilities**