Subpart G—Well Operations and Equipment

Source: 81 FR 26022, Apr. 29, 2016, unless otherwise noted.

General Requirements

§250.700 What operations and equipment does this subpart cover?

This subpart covers operations and equipment associated with drilling, completion, workover, and decommissioning activities. This subpart includes regulations applicable to drilling, completion, workover, and decommissioning activities in addition to applicable regulations contained in subparts D, E, F, and Q of this part unless explicitly stated otherwise.

§250.701 May I use alternate procedures or equipment during operations?

You may use alternate procedures or equipment during operations after receiving approval as described in §250.141. You must identify and discuss your proposed alternate procedures or equipment in your Application for Permit to Drill (APD) (Form BSEE-0123) (see §250.414(h)) or your Application for Permit to Modify (APM) (Form BSEE-0124). Procedures for obtaining approval of alternate procedures or equipment are described in §250.141.

§250.702 May I obtain departures from these requirements?

You may apply for a departure from these requirements as described in §250.142. Your request must include a justification showing why the departure is necessary. You must identify and discuss the departure you are requesting in your APD (see §250.414(h)) or your APM.

§250.703 What must I do to keep wells under control?

You must take the necessary precautions to keep wells under control at all times, including:

(a) Use recognized engineering practices to reduce risks to the lowest level practicable when monitoring and evaluating well conditions and to minimize the potential for the well to flow or kick;

(b) Have a person onsite during operations who represents your interests and can fulfill your responsibilities;

(c) Ensure that the toolpusher, operator's representative, or a member of the rig crew maintains continuous surveillance on the rig floor from the beginning of operations until the well is completed or abandoned, unless you have secured the well with blowout preventers (BOPs), bridge plugs, cement plugs, or packers;

(d) Use personnel trained according to the provisions of subparts O and S of this part;

(e) Use and maintain equipment and materials necessary to ensure the safety and protection of personnel, equipment, natural resources, and the environment; and

(f) Use equipment that has been designed, tested, and rated for the maximum environmental and operational conditions to which it may be exposed while in service.

Rig Requirements

§250.710 What instructions must be given to personnel engaged in well operations?

Prior to engaging in well operations, personnel must be instructed in:

(a) Hazards and safety requirements. You must instruct your personnel regarding the safety requirements for the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment as required by subpart S of this part. The date and time of safety meetings must be recorded and available at the facility for review by BSEE representatives.

(b) Well control. You must prepare a well-control plan for each well. Each well-control plan must contain instructions for personnel about the use of each well-control component of your BOP, procedures that describe how personnel will seal the wellbore and shear pipe before maximum anticipated surface pressure (MASP) conditions are exceeded, assignments for each crew member, and a schedule for completion of each assignment. You must keep a copy of your well-control plan on the rig at all times, and make it available to BSEE upon request. You must post a copy of the well-control plan on the rig floor.

§250.711 What are the requirements for well-control drills?

You must conduct a weekly well-control drill with all personnel engaged in well operations. Your drill must familiarize personnel engaged in well operations with their roles and functions so that they can perform their duties promptly and efficiently as outlined in the well-control plan required by §250.710.

(a) Timing of drills. You must conduct each drill during a period of activity that minimizes the risk to operations. The timing of your drills must cover a range of different operations, including drilling with a diverter, on-bottom drilling, and tripping. The same drill may not be repeated consecutively with the same crew.

(b) Recordkeeping requirements. For each drill, you must record the following in the daily report:

(1) Date, time, and type of drill conducted;

(2) The amount of time it took to be ready to close the diverter or use each well-control component of BOP system; and

(3) The total time to complete the entire drill.

(c) A BSEE ordered drill. A BSEE representative may require you to conduct a well-control drill during a BSEE inspection. The BSEE representative will consult with your onsite representative before requiring the drill.

§250.712 What rig unit movements must I report?

(a) You must report the movement of all rig units on and off locations to the District Manager using Form BSEE-0144, Rig Movement Notification Report. Rig units include MODUs, platform rigs, snubbing units, wire-line units used for non-routine operations, and coiled tubing units. You must inform the District Manager 24 hours before:

(1) The arrival of a rig unit on location;

(2) The movement of a rig unit to another slot. For movements that will occur less than 24 hours after initially moving onto location (e.g., coiled tubing and batch operations), you may include your anticipated movement schedule on Form BSEE-0144; or

(3) The departure of a rig unit from the location.

(b) You must provide the District Manager with the rig name, lease number, well number, and expected time of arrival or departure.

(c) If a MODU or platform rig is to be warm or cold stacked, you must inform the District Manager:

(1) Where the MODU or platform rig is coming from;

(2) The location where the MODU or platform rig will be positioned;

(3) Whether the MODU or platform rig will be manned or unmanned; and

(4) If the location for stacking the MODU or platform rig changes.

(d) Prior to resuming operations after stacking, you must notify the appropriate District Manager of any construction, repairs, or modifications associated with the drilling package made to the MODU or platform rig.

(e) If a drilling rig is entering OCS waters, you must inform the District Manager where the drilling rig is coming from.

(f) If you change your anticipated date for initially moving on or off location by more than 24 hours, you must submit an updated Form BSEE-0144, Rig Movement Notification Report.

(g) You are not required to report rig unit movements to and from the safe zone during the course of permitted operations.

(h) If a rig unit is already on a well, you are not required to report any additional rig unit movements on that well.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21976, May 15, 2019]

§250.713 What must I provide if I plan to use a mobile offshore drilling unit (MODU) for well operations?

If you plan to use a MODU for well operations, you must provide:

(a) Fitness requirements. Information and data to demonstrate the MODU's capability to perform at the proposed location. This information must include the maximum environmental and operational conditions that the MODU is designed to withstand, including the minimum air gap necessary for both hurricane and non-hurricane seasons. If sufficient environmental information and data are not available at the time you submit your APD or APM, the District Manager may approve your APD or APM, but require you to collect and report this information during operations. Under this circumstance, the District Manager may revoke the approval of the APD or APM if information collected during operations shows that the MODU is not capable of performing at the proposed location.

(b) Foundation requirements. Information to show that site-specific soil and oceanographic conditions are capable of supporting the proposed bottom-founded MODU. If you provided sufficient site-specific information in your EP, DPP, or DOCD submitted to BOEM for that well location and conditions, you may reference that information. The District Manager may require you to conduct additional surveys and soil borings before approving the APD or APM if additional information is needed to make a determination that the conditions are capable of supporting the MODU, or equipment installed on a subsea wellhead. For a moored rig, you must submit a plat of the rig's anchor pattern approved in your EP, DPP, or DOCD in your APD or APM.

(c) For frontier areas. (1) If the design of the MODU you plan to use in a frontier area is unique or has not been proven for use in the proposed environment, the District Manager may require you to submit a third-party review of the MODU design. If required, you must obtain a third-party review of your MODU similar to the process outlined in §§250.915 through 250.918. You may submit this information before submitting an APD or APM.

(2) If you plan to conduct operations in a frontier area, you must have a contingency plan that addresses design and operating limitations of the MODU. Your plan must identify the actions necessary to maintain safety and prevent damage to the environment. Actions must include the suspension, curtailment, or modification of operations to remedy various operational or environmental situations (e.g., vessel motion, riser offset, anchor tensions, wind speed, wave height, currents, icing or ice-loading, settling, tilt or lateral movement, resupply capability).

(d) Additional documentation. You must provide the current Certificate of Inspection (for U.S.-flag vessels) or Certificate of Compliance (for foreign-flag vessels) from the USCG and Certificate of Classification. You must also provide current documentation of any operational limitations imposed by an appropriate classification society.

(e) Dynamically positioned MODU. If you use a dynamically positioned MODU, you must include in your APD or APM your contingency plan for moving off location in an emergency situation. At a minimum, your plan must address emergency events caused by storms, currents, station-keeping failures, power failures, and losses of well control. The District Manager may require your plan to include additional events that may require movement of the MODU and other information needed to clarify or further address how the MODU will respond to emergencies or other events.

(f) Inspection of MODU. The MODU must be available for inspection by the District Manager before commencing operations and at any time during operations.

(g) Current monitoring. For water depths greater than 400 meters (1,312 feet), you must include in your APD or APM:

(1) A description of the specific current speeds that will cause you to implement rig shutdown, move-off procedures, or both; and

(2) A discussion of the specific measures you will take to curtail rig operations and move off location when such currents are encountered. You may use criteria, such as current velocities, riser angles, watch circles, and remaining rig power to describe when these procedures or measures will be implemented.

[81 FR 26022, Apr. 29, 2016, as amended at 81 FR 36150, June 6, 2016]

§250.714 Do I have to develop a dropped objects plan?

If you use a floating rig unit in an area with subsea infrastructure, you must develop a dropped objects plan and make it available to BSEE upon request. This plan must be updated as the infrastructure on the seafloor changes. Your plan must include:

(a) A description and plot of the path the rig will take while running and pulling the riser;

(b) A plat showing the location of any subsea wells, production equipment, pipelines, and any other identified debris;

(c) Modeling of a dropped object's path with consideration given to metocean conditions for various material forms, such as a tubular (e.g., riser or casing) and box (e.g., BOP or tree);

(d) Communications, procedures, and delegated authorities established with the production host facility to shut-in any active subsea wells, equipment, or pipelines in the event of a dropped object; and

(e) Any additional information required by the District Manager as appropriate to clarify, update, or evaluate your dropped objects plan.

§250.715 Do I need a global positioning system (GPS) for all MODUs?

All MODUs must have a minimum of two functioning GPS transponders at all times, and you must provide to BSEE real-time access to the GPS data prior to and during each hurricane season.

(a) The GPS must be capable of monitoring the position and tracking the path in real-time if the MODU moves from its location during a severe storm.

(b) You must install and protect the tracking system's equipment to minimize the risk of the system being disabled.

(c) You must place the GPS transponders in different locations for redundancy to minimize risk of system failure.

(d) Each GPS transponder must be capable of transmitting data for at least 7 days after a storm has passed.

(e) If the MODU is moved off location in the event of a storm, you must immediately begin to record the GPS location data.

(f) You must contact the Regional Office and allow real-time access to the MODU location data. When you contact the Regional Office, provide the following:

(1) Name of the lessee and operator with contact information;

(2) MODU name;

(3) Initial date and time; and

(4) How you will provide GPS real-time access.

Well Operations

§250.720 When and how must I secure a well?

(a) Whenever you interrupt operations, you must notify the District Manager. Before moving off the well, you must have two independent barriers installed, at least one of which must be a mechanical barrier, as approved by the District Manager. You must install the barriers at appropriate depths within a properly cemented casing string or liner. Before removing a subsea BOP stack or surface BOP stack on a mudline suspension well, you must conduct a negative pressure test in accordance with §250.721.

(1) The events that would cause you to interrupt operations and notify the District Manager include, but are not limited to, the following:

(i) Evacuation of the rig crew;

(ii) Inability to keep the rig on location;

(iii) Repair to major rig or well-control equipment;

(iv) Observed flow outside the well's casing (e.g., shallow water flow or bubbling); or

(v) Impending National Weather Service-named tropical storm or hurricane.

(2) The District Manager may approve alternate procedures or barriers, in accordance with §250.141, if you do not have time to install the required barriers or if special circumstances occur.

(3) If you unlatch the BOP or LMRP:

(i) Upon relatch of the BOP, you must test according to §250.734(b)(2), or

(ii) Upon relatch of the LMRP, you must test according to §250.734(b)(3); and

(iii) You must submit a revised permit with a written statement from an independent third party certifying that the previous certification under §250.731(c) remains valid and receive District Manager approval before resuming operations.

(b) Before you displace kill-weight fluid from the wellbore and/or riser, thereby creating an underbalanced state, you must obtain approval from the District Manager. To obtain approval, you must submit with your APD or APM your reasons for displacing the kill-weight fluid and provide detailed step-by-step written procedures describing how you will safely displace these fluids. The step-by-step displacement procedures must address the following:

(1) Number and type of independent barriers, as described in §250.420(b)(3), that are in place for each flow path that requires such barriers;

(2) Tests you will conduct to ensure integrity of independent barriers;

(3) BOP procedures you will use while displacing kill-weight fluids; and

(4) Procedures you will use to monitor the volumes and rates of fluids entering and leaving the wellbore.

(c) For Arctic OCS exploratory drilling operations, in addition to the requirements of paragraphs (a) and (b) of this section:

(1) If you move your drilling rig off a well prior to completion or permanent abandonment, you must ensure that any equipment left on, near, or in a wellbore that has penetrated below the surface casing is positioned in a manner to:

(i) Protect the well head; and

(ii) Prevent or minimize the likelihood of compromising the down-hole integrity of the well or the effectiveness of the well plugs.

(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. 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.

(d) You must have the equipment used solely for intervention operations (e.g., tree interface tools) identified, readily available, properly maintained, and available for BSEE inspection upon request. This equipment is required for subsea completed wells with a tree installed, that meet the following conditions:

(1) Have a shut-in tubing pressure that is greater than the hydrostatic pressure of the water column, or

(2) Are not capable of having the annulus monitored.

[81 FR 26022, Apr. 29, 2016, as amended at 81 FR 46563, July 15, 2016; 84 FR 21976, May 15, 2019]

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§250.721 What are the requirements for pressure testing casing and liners?

(a) You must test each casing string that extends to the wellhead according to the following table:

Casing type	Minimum test pressure
(1) Drive or Structural,	Not required.
(2) Conductor, excluding subsea wellheads,	250 psi.
(3) Surface, Intermediate, and Production,	70 percent of its minimum internal yield.

(b) You must test each drilling liner and liner-top to a pressure at least equal to the anticipated leak-off pressure of the formation below that liner shoe, or subsequent liner shoes if set. You must conduct this test before you continue operations in the well.

(c) You must test each production liner and liner-top to a minimum of 500 psi above the formation fracture pressure at the casing shoe into which the liner is lapped.

(d) The District Manager may approve or require other casing test pressures as appropriate under the circumstances to ensure casing integrity.

(e) If you plan to produce a well, you must:

(1) For a well that is fully cased and cemented, pressure test the entire well to maximum anticipated shut-in tubing pressure, not to exceed 70% of the burst rating limit of the weakest component before perforating the casing or liner; or

(2) For an open-hole completion, pressure test the entire well to maximum anticipated shut-in tubing pressure, not to exceed 70% of the burst rating limit of the weakest component before you drill the open-hole section.

(f) You may not resume operations until you obtain a satisfactory pressure test. If the pressure declines more than 10 percent in a 30-minute test, or if there is another indication of a leak, you must submit to the District Manager for approval your proposed plans to re-cement, repair the casing or liner, or run additional casing/liner to provide a proper seal. Your submittal must include a PE certification of your proposed plans.

(g) You must perform a negative pressure test on all wells that use a subsea BOP stack or wells with mudline suspension systems.

(1) You must perform a negative pressure test on your final casing string or liner. This test must be conducted after setting your second barrier just above the shoe track, but prior to conducting any completion operations.

(2) You must perform a negative pressure test prior to unlatching the BOP at any point in the well. The negative pressure test must be performed on those components, at a minimum, that will be exposed to the negative differential pressure that will occur when the BOP is disconnected.

(3) The District Manager may require you to perform additional negative pressure tests on other casing strings or liners (e.g., intermediate casing string or liner) or on wells with a surface BOP stack as appropriate to demonstrate casing or liner integrity.

(4) You must submit for approval with your APD or APM, test procedures and criteria for a successful negative pressure test. If any of your test procedures or criteria for a successful test change, you must submit for approval the changes in a revised APD or APM.

(5) You must document all your test results and make them available to BSEE upon request.

(6) If you have any indication of a failed negative pressure test, such as, but not limited to, pressure buildup or observed flow, you must immediately investigate the cause. If your investigation confirms that a failure occurred during the negative pressure test, you must:

(i) Correct the problem and immediately notify the appropriate District Manager; and

(ii) Submit a description of the corrective action taken and receive approval from the appropriate District Manager for the retest.

(7) You must have two barriers in place, as described in §250.420(b)(3), at any time and for any well, prior to performing the negative pressure test.

(8) You must include documentation of the successful negative pressure test in the End-of-Operations Report (Form BSEE-0125).

§250.722 What are the requirements for prolonged operations in a well?

If wellbore operations continue within a casing or liner for more than 30 days from the previous pressure test of the well's casing or liner, you must:

(a) Stop operations as soon as practicable, and evaluate the effects of the prolonged operations on continued operations and the life of the well. At a minimum, you must:

(1) Evaluate the well casing with a pressure test, caliper tool, or imaging tool. On a case-by-case basis, the District Manager may require a specific method of evaluation of the effects on the well casing of prolonged operations; and

(2) Report the results of your evaluation to the District Manager and obtain approval of those results before resuming operations. Your report must include calculations that indicate the well's integrity is above the minimum safety factors, if an imaging tool or caliper is used. District Manager approval is not required to resume operations if you conducted a successful pressure test as approved in your permit. You must document the successful pressure test in the WAR.

(b) If well integrity has deteriorated to a level below minimum safety factors, you must:

(1) Obtain approval from the District Manager to begin repairs or install additional casing. To obtain approval, you must also provide a PE certification showing that he or she reviewed and approved the proposed changes;

(2) Repair the casing or run another casing string; and

(3) Perform a pressure test after the repairs are made or additional casing is installed and report the results to the District Manager as specified in §250.721.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21977, May 15, 2019]

§250.723 What additional safety measures must I take when I conduct operations on a platform that has producing wells or has other hydrocarbon flow?

You must take the following safety measures when you conduct operations with a rig unit on or jacked-up over a platform with producing wells or that has other hydrocarbon flow:

(a) The movement of rig units and related equipment on and off a platform or from well to well on the same platform, including rigging up and rigging down, must be conducted in a safe manner;

(b) You must install an emergency shutdown station for the production system near the rig operator's console;

(c) You must shut-in all producible wells located in the affected wellbay below the surface and at the wellhead when:

(1) You move a rig unit or related equipment on and off a platform. This includes rigging up and rigging down activities within 500 feet of the affected platform;

(2) You move or skid a rig unit between wells on a platform; or

(3) A MODU moves within 500 feet of a platform. You may resume production once the MODU is in place, secured, and ready to begin operations.

(d) All wells in the same well-bay which are capable of producing hydrocarbons must be shut-in below the surface with a pump-through-type tubing plug and at the surface with a closed master valve prior to moving rig units and related equipment, unless otherwise approved by the District Manager.

(1) A closed surface-controlled subsurface safety valve of the pump-through-type may be used in lieu of the pump-through-type tubing plug provided that the surface control has been locked out of operation.

(2) The well to which a rig unit or related equipment is to be moved must be equipped with a back-pressure valve prior to removing the tree and installing and testing the BOP system.

(3) The well from which a rig unit or related equipment is to be moved must be equipped with a back pressure valve prior to removing the BOP system and installing the production tree.

(e) Coiled tubing units, snubbing units, or wireline units may be moved onto and off of a platform without shutting in wells.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21977, May 15, 2019]

§250.724 What are the real-time monitoring requirements?

(a) When conducting well operations with a subsea BOP or with a surface BOP on a floating facility, or when operating in an high pressure high temperature (HPHT) environment, you must gather and monitor real-time well data using an independent, automatic, and continuous monitoring system capable of recording, storing, and transmitting data regarding the following:

(1) The BOP control system;

(2) The well's active fluid circulating system; and

(3) The well's downhole conditions with the bottom hole assembly tools (if any tools are installed).

(b) You must transmit these data as they are gathered, barring unforeseeable or unpreventable interruptions in transmission, and have the capability to monitor the data, using qualified personnel in accordance with a real-time monitoring plan, as provided in paragraph (c) of this section.

(c) You must develop and implement a real-time monitoring plan. Your real-time monitoring plan, and all real-time monitoring data, must be made available to BSEE upon request. Your real-time monitoring plan must include the following:

(1) A description of your real-time monitoring capabilities, including the types of the data collected;

(2) A description of how your real-time monitoring data will be transmitted during operations, how the data will be labeled and monitored by qualified personnel, and how the data will be stored as required in §§250.740 and 250.741;

(3) A description of your procedures for providing BSEE access, upon request, to your real-time monitoring data;

(4) The qualifications of the personnel monitoring the data;

(5) Your procedures for, and methods of, communication between rig personnel and the monitoring personnel; and

(6) Actions to be taken if you lose any real-time monitoring capabilities or communications between rig personnel and monitoring personnel, and a protocol for how you will respond to any significant and/or prolonged interruption of monitoring capabilities or communications, including your protocol for notifying BSEE of any significant and/or prolonged interruptions.

[84 FR 21977, May 15, 2019]

Blowout Preventer (BOP) System Requirements

§250.730 What are the general requirements for BOP systems and system components?

(a) You must ensure that the BOP system and system components are designed, installed, maintained, inspected, tested, and used properly to ensure well control. The working-pressure rating of each BOP component (excluding annular(s)) must exceed MASP as defined for the operation. For a subsea BOP, the MASP must be determined at the mudline. The BOP system includes the BOP stack, control system, and any other associated system(s) and equipment. The BOP system and individual components must be able to perform their expected functions and be compatible with each other. Your BOP system must be capable of closing and sealing the wellbore in the event of flow due to a kick, including under anticipated flowing conditions for the specific well conditions, without losing ram closure time and sealing integrity due to the corrosiveness, volume, and abrasiveness of any fluids in the wellbore that the BOP system may encounter. Your BOP system must meet the following requirements:

(1) The BOP requirements of API Standard 53 (incorporated by reference in §250.198) and the requirements of §§250.733 through 250.739. If there is a conflict between API Standard 53 and the requirements of this subpart, you must follow the requirements of this subpart.

(2) The provisions of the following industry standards (all incorporated by reference in §250.198) that apply to BOP systems:

(i) ANSI/API Spec. 6A;

(ii) ANSI/API Spec. 16A;

(iii) ANSI/API Spec. 16C;

(iv) API Spec. 16D; and

(v) ANSI/API Spec. 17D.

(3) For surface and subsea BOPs, the pipe and variable bore rams installed in the BOP stack must be capable of effectively closing and sealing on the tubular body of any drill pipe, workstring, and tubing (excluding tubing with exterior control lines and flat packs) in the hole under MASP, as defined for the operation, at the proposed regulator settings of the BOP control system.

(4) The current set of approved schematic drawings must be available on the rig and at an onshore location. If you make any modifications to the BOP or control system that will require changes to your BSEE-approved schematic drawings, you must suspend operations until you obtain approval from the District Manager.

(b) You must ensure that the design, fabrication, maintenance, and repair of your BOP system is in accordance with the requirements contained in this part, applicable Original Equipment Manufacturer's (OEM) recommendations unless otherwise directed by BSEE, and recognized engineering practices. The training and qualification of repair and maintenance personnel must meet or exceed applicable OEM training recommendations unless otherwise directed by BSEE.

(c) You must follow the failure reporting procedures contained in API Standard 53, (incorporated by reference in §250.198), and:

(1) You must provide a written notice of equipment failure to the Chief, Office of Offshore Regulatory Programs (OORP), unless BSEE has designated a third party as provided in paragraph (c)(4) of this section, and the manufacturer of such equipment within 30 days after the discovery and identification of the failure. A failure is any condition that prevents the equipment from meeting the functional specification.

(2) You must ensure that an investigation and a failure analysis are started within 120 days of the failure to determine the cause of the failure, and are completed within 120 days upon starting the investigation and failure analysis. You must also ensure that the results and any corrective action are documented. You must ensure that the analysis report is submitted to the Chief OORP, unless BSEE has designated a third party as provided in paragraph (c)(4) of this section, as well as the manufacturer. If you cannot complete the investigation and analysis within the specified time, you must submit an extension request detailing how you will complete the investigation and analysis to BSEE for approval. You must submit the extension request to the Chief, OORP.

(3) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such changes, report the design change or modified procedures in writing to the Chief OORP, unless BSEE has designated a third party as provided in paragraph (c)(4) of this section.

(4) Submit notices and reports to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, Virginia 20166. BSEE may designate a third party to receive the data and reports on behalf of BSEE. If BSEE designates a third party, you must submit the data and reports to the designated third party.

(d) If you plan to use a BOP stack manufactured after the effective date of this regulation, you must use one manufactured pursuant to an ANSI/API Spec. Q1 (as incorporated by reference in §250.198) quality management system. Such quality management system must be certified by an entity that meets the requirements of ISO/IEC 17021-1 (as incorporated by reference in §250.198).

(1) BSEE may consider accepting equipment manufactured under quality assurance programs other than ANSI/API Spec. Q1, provided you submit a request to the Chief, OORP for approval, containing relevant information about the alternative program.

(2) You must submit this request to the Chief, OORP; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, Virginia 20166.

[84 FR 21977, May 15, 2019]

§250.731 What information must I submit for BOP systems and system components?

For any operation that requires the use of a BOP, you must include the information listed in this section with your applicable APD, APM, or other submittal. You are required to submit this information only once for each well, unless the information changes from what you provided in an earlier approved submission or you have moved off location from the well. After you have submitted this information for a particular well, subsequent APMs or other submittals for the well should reference the approved submittal containing the information required by this section and confirm that the information remains accurate and that you have not moved off location from that well. If the information changes or you have moved off location from the well, you must submit updated information in your next submission.

You must submit: Including:

(a) A complete description of the BOP system and system components, (1) Pressure ratings of BOP equipment;

(2) Proposed BOP test pressures (for subsea BOPs, include both surface and corresponding subsea pressures);

(3) Rated capacities for liquid and gas for the fluid-gas separator system;

(4) Control fluid volumes needed to close, seal, and open each component;

(5) Control system pressure and regulator settings needed to close each ram BOP under MASP as defined for the operation;

(6) Number and volume of accumulator bottles and bottle banks (for subsea BOP, include both surface and subsea bottles);

(7) Accumulator pre-charge calculations (for subsea BOP, include both surface and subsea calculations);

(8) All locking devices; and

(9) Control fluid volume calculations for the accumulator system (for a subsea BOP system, include both the surface and subsea volumes).

(b) Schematic drawings, (1) The inside diameter of the BOP stack;

(2) Number and type of preventers (including blade type for shear ram(s));

(3) All locking devices;

(4) Size range for variable bore ram(s);

(5) Size of fixed ram(s);

(6) All control systems with all alarms and set points labeled, including pods;

(7) Location and size of choke and kill lines (and gas bleed line(s) for subsea BOP);

(8) Associated valves of the BOP system;

(9) Control station locations; and

(10) A cross-section of the riser for a subsea BOP system showing number, size, and labeling of all control, supply, choke, and kill lines down to the BOP.

(c) Certification by an independent third party, Verification that:

(1) Test data demonstrate the shear ram(s) will shear the drill pipe at the water depth as required in §250.732;

(2) The BOP was designed, tested, and maintained to perform under the maximum environmental and operational conditions anticipated to occur at the well;

(3) The accumulator system has sufficient fluid to operate the BOP system without assistance from the charging system; and

(4) If using a subsea BOP, a BOP in an HPHT environment as defined in §250.804(b), or a surface BOP on a floating facility, the BOP has not been compromised or damaged from previous service.

(d) If you are using a subsea BOP, descriptions of autoshear, deadman, and emergency disconnect sequence (EDS) systems, A listing of the functions with their sequences and timing.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21978, May 15, 2019]

§250.732 What are the independent third party requirements for BOP systems and system components?

(a) Prior to beginning any operation requiring the use of any BOP, you must submit verification by an independent third party and supporting documentation as required by this paragraph to the appropriate District Manager and Regional Supervisor.

You must submit verification and documentation related to: That:

(1) Shear testing, (i) Demonstrates that the BOP will shear the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies such as heavy-weight pipe or collars), workstring, tubing and associated exterior control lines and any electric-, wire-, and slick-line to be used in the well;

(ii) Demonstrates the use of test protocols and analysis that represent recognized engineering practices for ensuring the repeatability and reproducibility of the tests, and that the testing was performed by a facility that meets generally accepted quality assurance standards;

(iii) Provides a reasonable representation of field applications, taking into consideration the physical and mechanical properties of the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies such as heavy-weight pipe or collars), workstring, tubing and associated exterior control lines and any electric-, wire-, and slick-line to be used in the well;

(iv) Ensures testing was performed on the outermost edges of the shearing blades of the shear ram;

(v) Demonstrates the shearing capacity of the BOP equipment to the physical and mechanical properties of the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies such as heavy-weight pipe or collars), workstring, tubing and associated exterior control lines and any electric-, wire-, and slick-line to be used in the well; and

(vi) Includes relevant testing results.

(2) Pressure integrity testing for sealing components, and (i) Shows that testing is conducted after the shearing is completed and prior to opening the component;

(ii) Demonstrates that the equipment will seal at the rated working pressures (RWP) of the BOP for 5 minutes; and

(iii) Includes all relevant test results.

(3) Calculations Include shearing and sealing pressures for all pipe to be used in the well including corrections for MASP.

(b) The independent third-party must be a technical classification society, a licensed professional engineering firm, or a registered professional engineer capable of providing the required certifications and verifications.

(c) For wells in an HPHT environment, as defined by §250.804(b), you must submit verification by an independent third party that it conducted a comprehensive review of the BOP system and related equipment you propose to use. You must provide the independent third party access to any facility associated with the BOP system or related equipment during the review process. You must submit the verifications required by this paragraph (c) to the appropriate District Manager and Regional Supervisor before you begin any operations in an HPHT environment with the proposed equipment.

You must submit: Including:

(1) Verification that the independent third party conducted a detailed review of the design package to ensure that all critical components and systems meet recognized engineering practices,

(2) Verification that the designs of individual components and the overall system have been proven in a testing process that demonstrates the performance and reliability of the equipment in a manner that is repeatable and reproducible, (i) Identification of all reasonable potential modes of failure; and

(ii) Evaluation of the design verification tests. The design verification tests must assess the equipment for the identified potential modes of failure.

(3) Verification that the BOP equipment will perform as designed in the temperature, pressure, and environment that will be encountered, and

(4) Verification that the fabrication, manufacture, and assembly of individual components and the overall system uses recognized engineering practices and quality control and assurance mechanisms.

For the quality control and assurance mechanisms, complete material and quality controls over all contractors, subcontractors, distributors, and suppliers at every stage in the fabrication, manufacture, and assembly process.

(d) You must make all documentation that demonstrates compliance with the requirements of this section available to BSEE upon request.

[84 FR 21978, May 15, 2019]

§250.733 What are the requirements for a surface BOP stack?

(a) When you drill or conduct operations with a surface BOP stack, you must install the BOP system before drilling or conducting operations to deepen the well below the surface casing and after the well is deepened below the surface casing point. The surface BOP stack must include at least four remote-controlled, hydraulically operated BOPs, consisting of one annular BOP, one BOP equipped with blind shear rams, and two BOPs equipped with pipe rams.

(1) The blind shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that include heavy-weight pipe or collars), workstring, tubing and associated exterior control lines, and any electric-, wire-, and slick-line that is in the hole and sealing the wellbore after shearing. Prior to April 29, 2021, if your blind shear rams are unable to cut any electric-, wire-, or slick-line under MASP as defined for the operation and seal the wellbore, you must use an alternative cutting device capable of shearing the lines before closing the BOP. This device must be available on the rig floor during operations that require their use.

(2) The two BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, except for tubing with exterior control lines and flat packs, a bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools.

(b) If you plan to use a surface BOP on a floating production facility you must:

(1) On new floating production facilities installed after April 29, 2021, that include a surface BOP, follow the BOP requirements in §250.734(a)(1).

(2) For risers installed after July 28, 2016, use a dual bore riser configuration before drilling or operating in any hole section or interval where hydrocarbons are, or may be, exposed to the well. The dual bore riser must meet the design requirements of API RP 2RD (as incorporated by reference in §250.198), including appropriate design for the maximum anticipated operating and environmental conditions.

(i) For a dual bore riser configuration, the annulus between the risers must be monitored for pressure during operations. You must describe in your APD or APM your annulus monitoring plan and how you will secure the well in the event a leak is detected.

(ii) The inner riser for a dual riser configuration is subject to the requirements at §250.721 for testing the casing or liner.

(c) You must install separate side outlets on the BOP stack for the kill and choke lines. If your stack does not have side outlets, you must install a drilling spool with side outlets. The outlet valves must hold pressure from both directions.

(d) You must install a choke and a kill line on the BOP stack. You must equip each line with two full-bore, full-opening valves, one of which must be remote-controlled. On the kill line, you may install a check valve and a manual valve instead of the remote-controlled valve. To use this configuration, both manual valves must be readily accessible and you must install the check valve between the manual valves and the pump.

(e) Additional requirements for surface BOP systems used in well-completion, workover, and decommissioning operations. The minimum BOP system for well-completion, workover, and decommissioning operations must meet the appropriate standards from the following table:

When . . . The minimum BOP stack must include . . .

(1) The expected pressure is less than 5,000 psi, Three BOPs consisting of an annular, one set of pipe rams, and one set of blind-shear rams.

(2) The expected pressure is 5,000 psi or greater or you use multiple tubing strings, Four BOPs consisting of an annular, two sets of pipe rams, and one set of blind-shear rams.

(3) You handle multiple tubing strings simultaneously, Four BOPs consisting of an annular, one set of pipe rams, one set of dual pipe rams, and one set of blind-shear rams.

(4) You use a tapered drill pipe, work string, or tubing, At least one set of pipe rams that are capable of sealing around each size of drill pipe, work string, or tubing. If the expected pressure is greater than 5,000 psi, then you must have at least two sets of pipe rams that are capable of sealing around the larger size drill pipe, work string, or tubing. You may substitute one set of variable bore rams for two sets of pipe rams.

(5) You use a surface BOP on a floating facility, The elements required by §250.733(b)(1) of this part.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21979, May 15, 2019]

§250.734 What are the requirements for a subsea BOP system?

(a) When you drill or conduct operations with a subsea BOP system, you must install the BOP system before drilling to deepen the well below the surface casing or before conducting operations if the well is already deepened beyond the surface casing point. The District Manager may require you to install a subsea BOP system before drilling or conducting operations below the conductor casing if proposed casing setting depths or local geology indicate the need. The following table outlines your requirements.

When operating with a subsea BOP system, you must: Additional requirements:

(1) Have at least five remote-controlled, hydraulically operated BOPs; You must have at least one annular BOP, two BOPs equipped with pipe rams, and two BOPs equipped with shear rams. For the dual ram requirement, you must comply with this requirement no later than April 29, 2021.

(i) Both BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, except tubing with exterior control lines and flat packs, a bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools.

(ii) Both shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies such as heavy-weight pipe or collars), workstring, tubing and associated exterior control lines, appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric-, wire-, slick-line in the hole; under MASP. At least one shear ram must be capable of sealing the wellbore after shearing under MASP conditions as defined for the operation. Any non-sealing shear ram(s) must be installed below a sealing shear ram(s).

(2) Have an operable redundant pod control system to ensure proper and independent operation of the BOP system;

(3) Have the accumulator capacity, to provide fast closure of the BOP components and to operate all critical functions; The accumulator capacity must:

(i) Close each required shear ram, ram locks, one pipe ram, and disconnect the LMRP.

(ii) Have the capability to perform ROV functions within the required times outlined in API Standard 53 with ROV or flying leads.

(iii) Have bottles located subsea for the autoshear and deadman (which may be shared between those two systems) to secure the wellbore. These bottles may also be utilized to perform the secondary control system functions (e.g., ROV or acoustic functions).

(iv) Perform under MASP conditions as defined for the operation.

(4) Have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention capability; You must have the ROV intervention capability to close each shear ram, ram locks, one pipe ram, and disconnect the LMRP under MASP conditions as defined for the operation. You must be capable of performing these functions in the response times outlined in API Standard 53 (as incorporated by reference in §250.198). The ROV panels on the BOP and LMRP must be compliant with API RP 17H (as incorporated by reference in §250.198).

(5) Maintain an ROV and have a trained ROV crew on each rig unit on a continuous basis once BOP deployment has been initiated from the rig until recovered to the surface. The ROV crew must examine all ROV-related well-control equipment (both surface and subsea) to ensure that it is properly maintained and capable of carrying out appropriate tasks during emergency operations; The crew must be trained in the operation of the ROV. The training must include simulator training on stabbing into an ROV intervention panel on a subsea BOP stack. The ROV crew must be in communication with designated rig personnel who are knowledgeable about the BOP's capabilities.

(6) Provide autoshear, deadman, and EDS systems for dynamically positioned rigs; provide autoshear and deadman systems for moored rigs; (i) Autoshear system means a safety system that is designed to automatically shut-in the wellbore in the event of a disconnect of the LMRP. This is considered a rapid discharge system.

(ii) Deadman system means a safety system that is designed to automatically shut-in the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods. This is considered a rapid discharge system.

(iii) Emergency Disconnect Sequence (EDS) system means a safety system that is designed to be manually activated to shut-in the wellbore and disconnect the LMRP in the event of an emergency situation. This is considered a rapid discharge system.

(iv) Autoshear/deadman functions and an EDS mode must close, at a minimum, two shear rams in sequence and be capable of performing their expected shearing and sealing action under MASP conditions as defined for the operation.

(v) Your sequencing must allow a sufficient delay when closing your two shear rams in order to provide maximum sealing efficiency.

(7) Demonstrate that any acoustic control system will function in the proposed environment and conditions; If you choose to use an acoustic control system in addition to the autoshear, deadman, and EDS requirements, you must demonstrate to the District Manager, as part of the information submitted under §250.731, that the acoustic control system will function in the proposed environment and conditions. The District Manager may require additional information as appropriate to clarify or evaluate the acoustic control system information provided in your demonstration.

(8) Have operational or physical barrier(s) on BOP control panels to prevent accidental disconnect functions; You must incorporate enable buttons, or a similar feature, on control panels to ensure two-handed operation for all critical functions.

(9) Clearly label all control panels for the subsea BOP system; Label other BOP control panels, such as hydraulic control panel.

(10) Develop and use a management system for operating the BOP system, including the prevention of accidental or unplanned disconnects of the system; The management system must include written procedures for operating the BOP stack and LMRP (including proper techniques to prevent accidental disconnection of these components) and minimum knowledge requirements for personnel authorized to operate and maintain BOP components.

(11) Establish minimum requirements for personnel authorized to operate critical BOP equipment; Personnel must have:

(i) Training in deepwater well-control theory and practice according to the requirements of Subparts O and S; and

(ii) A comprehensive knowledge of BOP hardware and control systems.

(12) Before removing the marine riser, displace the fluid in the riser with seawater; You must maintain sufficient hydrostatic pressure or take other suitable precautions to compensate for the reduction in pressure and to maintain a safe and controlled well condition. You must follow the requirements of §250.720(b).

(13) Install the BOP stack in a well cellar when in an ice-scour area; Your well cellar must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.

(14) Install at least two side outlets for a choke line and two side outlets for a kill line; (i) If your stack does not have side outlets, you must install a drilling spool with side outlets.

(ii) Each side outlet must have two full-bore, full-opening valves.

(iii) The valves must hold pressure from both directions and must be remote-controlled.

iv) You must install a side outlet below the lowest sealing shear ram. You may have a pipe ram or rams between the shearing ram and side outlet.

(15) Install a gas bleed line with two valves for the annular preventer no later than April 30, 2018;
(i) The valves must hold pressure from both directions;

(ii) If you have dual annulars, you must install the gas bleed line below the upper annular.

(16) Use a BOP system that has the following mechanisms and capabilities; (i) No later than May 1, 2023, you must have the capability to position the entire pipe completely within the area of the shearing blade. This capability cannot be a separate ram BOP or annular preventer, but you may use those during a planned shear.

(ii) If your control pods contain a subsea electronic module with batteries, a mechanism for personnel on the rig to monitor the state of charge of the subsea electronic module batteries in the BOP control pods.

(b) If you suspend operations to make repairs to any part of the subsea BOP system, you must stop operations at a safe downhole location. Before resuming operations you must:

(1) Submit a revised permit with a written statement from an independent third party documenting the repairs and certifying that the previous certification in §250.731(c) remains valid;

(2) Upon relatch of the BOP, perform an initial subsea BOP test in accordance with §250.737(d)(4), including deadman in accordance with §250.737(d)(12)(vi). If repairs take longer than 30 days, once the BOP is on deck, you must test in accordance with the requirements of §250.737;

(3) Upon relatch of the LMRP, you must test according to the following:

(i) Pressure test riser connector/gasket in accordance with §250.737(b) and (c);

(ii) Pressure test choke and kill stabs at LMRP/BOP interface in accordance with §250.737(b) and (c);

(iii) Full function test of both pods and both control panels;

(iv) Verify acoustic pod communication (if equipped); and

(v) Deadman test with pressure test in accordance with §250.737(d)(12)(vi).

(4) Receive approval from the District Manager.

(c) If you plan to drill a new well with a subsea BOP, you do not need to submit with your APD the verifications required by this subpart for the open water drilling operation. Before drilling out the surface casing, you must submit for approval a revised APD, including the verifications required in this subpart.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21980, May 15, 2019]

§250.735 What associated systems and related equipment must all BOP systems include?

All BOP systems must include the following associated systems and related equipment:

(a) An accumulator system (as specified in API Standard 53, incorporated by reference in §250.198). Your accumulator system must have the fluid volume capacity and appropriate pre-charge pressures in accordance with API Standard 53. If you supply the accumulator regulators by rig air and do not have a secondary source of pneumatic supply, you must equip the regulators with manual overrides or other devices to ensure capability of hydraulic operations if rig air is lost;

(b) An automatic backup to the primary accumulator-charging system. The power source must be independent from the power source for the primary accumulator-charging system. The independent power source must possess sufficient capability to close and hold closed all BOP components under MASP conditions as defined for the operation;

(c) At least two full BOP control stations. One station must be on the rig floor. You must locate the other station in a readily accessible location away from the rig floor;

(d) The choke line(s) installed above the bottom well-control ram;

(e) The kill line must be installed beneath at least one well-control ram, and may be installed below the bottom ram;

(f) A fill-up line above the uppermost BOP;

(g) Locking devices for all BOP sealing rams (i.e., blind shear rams, pipe rams and variable bore rams), as follows:

(1) For subsea BOPs, hydraulic locking devices must be installed on all sealing rams;

(2) For surface BOPs:

(i) Remotely-operated locking devices must be installed on blind shear rams no later than April 29, 2019;

(ii) Manual or remotely-operated locking devices must be installed on pipe rams and variable bore rams; and

(h) A wellhead assembly with a RWP that exceeds the maximum anticipated wellhead pressure.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21981, May 15, 2019]

§250.736 What are the requirements for choke manifolds, kelly-type valves inside BOPs, and drill string safety valves?

(a) Your BOP system must include a choke manifold that is suitable for the anticipated surface pressures, anticipated methods of well control, the surrounding environment, and the corrosiveness, volume, and abrasiveness of drilling fluids and well fluids that you may encounter.

(b) Choke manifold components must have a RWP at least as great as the RWP of the ram BOPs. If your choke manifold has buffer tanks downstream of choke assemblies, you must install isolation valves on any bleed lines.

(c) Valves, pipes, flexible steel hoses, and other fittings upstream of the choke manifold must have a RWP at least as great as the RWP of the ram BOPs.

(d) You must use the following BOP equipment with a RWP and temperature of at least as great as the working pressure and temperature of the ram BOP during all operations:

(1) The applicable kelly-type valves as described in API Standard 53 (incorporated by reference in §250.198);

(2) On a top-drive system equipped with a remote-controlled valve, a strippable kelly-type valve must be installed below the remote-controlled valve;

(3) An inside BOP in the open position located on the rig floor. You must be able to install an inside BOP for each size connection in the pipe;

(4) A drill string safety valve in the open position located on the rig floor. You must have a drill-string safety valve available for each size connection in the pipe;

(5) When running casing, a safety valve in the open position available on the rig floor to fit the casing string being run in the hole. For subsea BOPs, the safety valve must be available on the rig floor if the length of casing being run exceeds the water depth, which would result in the casing being across the BOP stack and the rig floor prior to crossing over to the drill pipe running string;

(6) All required manual and remote- controlled kelly-type valves, drill-string safety valves, and comparable-type valves (i.e., kelly-type valve in a top-drive system) that are essentially full opening; and

(7) A wrench to fit each manual valve. Each wrench must be readily accessible to the drilling crew.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21981, May 15, 2019]

§250.737 What are the BOP system testing requirements?

Your BOP system (this includes the choke manifold, kelly-type valves, inside BOP, and drill string safety valve) must meet the following testing requirements:

(a) Pressure test frequency. You must pressure test your BOP system:

(1) When installed;

(2) Before 14 days have elapsed since your last BOP pressure test, or 30 days since your last blind shear ram BOP pressure test. You must begin to test your BOP system before midnight on the 14th day (or 30th day for your blind shear rams) following the conclusion of the previous test;

(3) Before drilling out each string of casing or a liner. You may omit this pressure test requirement if you did not remove the BOP stack to run the casing string or liner, the required BOP test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test, and the time elapsed between tests has not exceeded 14 days (or 30 days for blind shear rams). You must indicate in your APD which casing strings and liners meet these criteria;

(4) In lieu of meeting the schedule established in paragraph (a)(2) of this section, you may request that BSEE approve a 21-day BOP testing frequency. To obtain BSEE approval, you must submit a request to the appropriate BSEE Regional Supervisor, District Field Operations. Your request must demonstrate that you have developed a BOP health monitoring plan that includes certain system capabilities. As long as your plan is consistent with recognized engineering and industry practice, BSEE will approve your request if it includes the following:

(i) Condition monitoring tools, including continuous surveillance of sensor readings from the BOP control system, real-time condition analysis and displays, functional pressure signal analysis, historical sensor data;

(ii) Failure propagation analysis;

(iii) A failure tracking and resolution system that includes detailed failure reports and identification of recurring problems; and

(iv) Submission of quarterly reports of the data collected pursuant to paragraphs (a)(4)(i)(iii) to the BSEE Regional Supervisor, District Field Operations.

(5) The District Manager may require more frequent testing if conditions or your BOP performance warrant.

(b) Pressure test procedures. When you pressure test the BOP system, you must conduct a low-pressure test and a high-pressure test for each BOP component (excluding test rams and non-sealing shear rams). You must begin each test by conducting the low-pressure test then transition to the high-pressure test. Each individual pressure test must hold pressure long enough to demonstrate the tested component(s) holds the required pressure. The table in this paragraph (b) outlines your pressure test requirements.

You must conduct a . . . According to the following procedures . . .

(1) Low-pressure test All low-pressure tests must be between 250 and 350 psi. Any initial pressure above 350 psi must be bled back to a pressure between 250 and 350 psi before starting the test. If the initial pressure exceeds 500 psi, you must bleed back to zero and reinitiate the test.

(2) High-pressure test for blind shear ram-type BOPs, ram-type BOPs, the choke manifold, outside of all choke and kill side outlet valves (and annular gas bleed valves for subsea BOP), inside of all choke and kill side outlet valves below uppermost ram, and other BOP components(i) The high-pressure test must equal the RWP of the equipment or be 500 psi greater than your calculated MASP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP plus 500 psi, the District Manager must have approved those test pressures in your permit.

(ii) The blind shear ram (BSR) must be tested to:

(A) MASP plus 500 psi for the hole section to which it is exposed; or

(B) Full well MASP plus 500 psi on initial latch up and all subsequent BSR pressure tests can be done to the casing/liner test pressure for the applicable hole section.

(iii) The choke and kill side outlet valves must be tested to, except as provided in paragraph (d)(13) of this section:

(A) MASP plus 500 psi for the hole section to which it is exposed; or

(B) Full well MASP plus 500 psi on initial latch up and all subsequent pressure tests can be done to the casing/liner test pressure for the applicable hole section.

(3) High-pressure test for annular-type BOPs, inside of choke or kill valves (and annular gas bleed valves for subsea BOP) above the uppermost ram BOP The high pressure test must equal 70 percent of the RWP of the equipment or be 500 psi greater than your calculated MASP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP plus 500 psi, the District Manager must have approved those test pressures in your APD or APM.

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

(d) Additional test requirements. You must meet the following additional BOP testing requirements:

You must . . . Additional requirements . . .

(1) Follow the testing requirements of API Standard 53 (as incorporated in §250.198) If there is a conflict between API Standard 53, testing requirements and this section, you must follow the requirements of this section.

(2) Use water to test a surface BOP system on the initial test. You may use drilling/completion/workover fluids to conduct subsequent tests of a surface BOP system (i) You must submit test procedures with your APD or APM for District Manager approval.

(ii) Contact the District Manager at least 72 hours prior to beginning the initial test to allow BSEE representative(s) to witness testing.

(3) Stump test a subsea BOP system before installation (i) You must use water to conduct this test. You may use drilling/completion/workover fluids to conduct subsequent tests of a subsea BOP system.

(ii) You must submit test procedures with your APD or APM for District Manager approval

(iii) Contact the District Manager at least 72 hours prior to beginning the stump test to allow BSEE representative(s) to witness testing.

(iv) You must verify closure of all ROV intervention functions on your subsea BOP stack during the stump test.

(v) You must follow paragraphs (b) and (c) of this section. Pressure testing of each ram and annular component is only required once.

(4) Perform an initial subsea BOP test (i) You must begin the initial subsea BOP test on the seafloor within 30 days of the stump test.

(ii) You must submit test procedures with your APD or APM for District Manager approval.

(iii) You must pressure test well-control rams and annulars according to paragraphs (b) and (c) of this section.

(iv) You must notify the District Manager at least 72 hours prior to beginning the initial subsea test for the BOP system to allow BSEE representative(s) to witness testing.

(v) You must test and verify closure of at least one set of rams during the initial subsea test through a ROV hot stab. You must confirm closure of the selected ram through the ROV hot stab with a 1,000 psi pressure test for 5 minutes.

(5) Alternate tests between control stations (i) For two complete BOP control stations you must:

(A) Designate a primary and secondary station;

(B) Alternate testing between the primary and secondary control stations on a weekly basis; and

(C) For a subsea BOP, develop an alternating testing schedule to ensure the primary and secondary control stations will function each pod.

(ii) Remote panels where all BOP functions are not included (e.g., life boat panels) must be function-tested upon the initial BOP tests.

(6) Pressure test variable bore-pipe ram BOPs against pipe sizes according to API Standard 53, excluding the bottom hole assembly that includes heavy-weight pipe or collars and bottom-hole tools

(7) Pressure test annular type BOPs against pipe sizes according to API Standard 53

(8) Pressure test affected BOP components following the disconnection or repair of any well-pressure containment seal in the wellhead or BOP stack assembly

(9) Function test annular and pipe/variable bore ram BOPs every 7 days between pressure tests

(10) Function test shear ram(s) BOPs every 14 days If BSEE approves your request to utilize a 21-day BOP test frequency pursuant to §250.737(a)(4), you may function test shear ram(s) BOPs every 21 days in accordance with the terms of that approval.

(11) Actuate safety valves assembled with proper casing connections before running casing

(12) Function test autoshear/deadman, and EDS systems separately on your subsea BOP stack during the stump test. The District Manager may require additional testing of the emergency systems. You must also test the deadman system and verify closure of the shearing rams during the initial test on the seafloor (i) You must submit test procedures with your APD or APM for District Manager approval. The procedures for these function tests must include the schematics of the actual controls and circuitry of the system that will be used during an actual autoshear or deadman event.

(ii) The procedures must also include the actions and sequence of events that take place on the approved schematics of the BOP control system and describe specifically how the ROV will be utilized during this operation.

(iii) When you conduct the initial deadman system test on the seafloor, you must ensure the well is secure and, if hydrocarbons have been present, appropriate barriers are in place to isolate hydrocarbons from the wellhead. You must also have an ROV on bottom during the test.

(iv) Following the deadman system test on the seafloor you must document the final remaining pressure of the subsea accumulator system.

(v) For the function test of the deadman system during the initial test on the seafloor, you must have the ability to quickly disconnect the LMRP should the rig experience a loss of station-keeping event. You must include your quick-disconnect procedures with your deadman test procedures.

(vi) You must confirm closure of the BSR(s) with a 1,000 psi pressure test for 5 minutes.

(vii) If a casing shear ram is installed, you must describe how you will verify closure of the ram.

(viii) You must document all your test results and make them available to BSEE upon request.

(13) Pressure test the choke and kill side outlet valves According to paragraph (b) of this section, except as follows:

(i) Test the wellbore side of the choke and kill side outlet valves above the uppermost pipe ram to the approved annular test pressure. Choke and kill side outlet valves below the uppermost pipe ram must be tested to MASP plus 500 psi for the applicable hole section.

(ii) For the 30 day BSR testing, test the wellbore side of the choke and kill side outlet valves between the upper most pipe ram and the upper most ram, to the casing/liner test pressure or annular test pressure, whichever is greater.

(iii) For BOPs with only one choke and kill side outlet valve, you are only required to pressure test the choke and kill side outlet valves from the wellbore side.

(e) Prior to conducting any shear ram tests in which you will shear pipe, you must notify the District Manager at least 72 hours in advance, to ensure that a BSEE representative will have access to the location to witness any testing.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21981, May 15, 2019]

§250.738 What must I do in certain situations involving BOP equipment or systems?

The table in this section describes actions that you must take when certain situations occur with BOP systems.

If you encounter the following situation:Then you must . . .

(a) BOP equipment does not hold the required pressure during a test; Correct the problem and retest the affected equipment. You must report any problems or irregularities, including any leaks, on the daily report as required in §250.746.

(b) Need to repair, replace, or reconfigure a surface BOP or subsea BOP system; (1) First place the well in a safe, controlled condition as approved by the District Manager (e.g., before drilling out a casing shoe or after setting a cement plug, bridge plug, or a packer).

(2) Any repair or replacement parts must be manufactured under a quality assurance program and must meet or exceed the performance of the original part produced by the OEM.

(3) 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 under §250.731(c) remains valid.

(4) You must receive approval from the District Manager prior to resuming operations.

(c) Need to postpone a BOP test due to well-control problems such as lost circulation, formation fluid influx, or stuck pipe; Record the reason for postponing the test in the daily report and conduct the required BOP test after the first trip out of the hole.

(d) BOP control station or pod that does not function properly; Suspend operations until that station or pod is operable. You must report any problems or irregularities, including any leaks, to the District Manager.

(e) Plan to operate with a tapered string; Install two or more sets of conventional or variable-bore pipe rams in the BOP stack to provide for the following: two sets of rams must be capable of sealing around the larger-size drill string and one set of pipe rams must be capable of sealing around the smaller size pipe, excluding the bottom hole assembly that includes heavy weight pipe or collars and bottom-hole tools.

(f) Plan to install casing rams or casing shear rams in a surface BOP stack; Before running casing, perform a shell test to the permit approved test pressure of the BOP component above the casing ram/casing shear. If this installation was not included in your approved permit, and changes the BOP configuration approved in the APD or APM, you must notify and receive approval from the District Manager.

(g) Plan to use an annular BOP with a RWP less than the anticipated surface pressure; Demonstrate that your well-control procedures or the anticipated well conditions will not place demands above its RWP and obtain approval from the District Manager.

(h) Plan to use a subsea BOP system in an ice-scour area; Install the BOP stack in a well cellar. The well cellar must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.

(i) You activate any shear ram and pipe or casing is sheared; Retrieve, physically inspect, and conduct a full pressure test of the BOP stack after the situation is fully controlled. You must submit to the District Manager a report from an independent third party certifying that the BOP is fit to return to service.

(j) Need to remove the BOP stack; Have a minimum of two barriers in place prior to BOP removal. You must obtain approval from the District Manager of the two barriers prior to removal and the District Manager may require additional barriers and test(s).

(k) In the event of a deadman or autoshear activation, if there is a possibility of the blind shear ram opening immediately upon re-establishing power to the BOP stack; Place the blind shear ram opening function in the block position prior to re-establishing power to the stack. Contact the District Manager and receive approval of procedures for re-establishing power and functions prior to latching up the BOP stack or re-establishing power to the stack.

(l) If a test ram is to be used; The wellhead/BOP connection must be tested to the MASP plus 500 psi for the hole section to which it is exposed. This can be done by:

(1) Testing wellhead/BOP connection to the MASP plus 500 psi for the well upon installation;

(2) Pressure testing each casing to the MASP plus 500 psi for the next hole section; or

(3) Some combination of paragraphs (l)(1) and (2) of this section.

(m) Plan to utilize any other circulating or ancillary equipment (e.g., but not limited to, subsea isolation device, subsea accumulator module, or gas handler) that is in addition to the equipment required in this subpart; Contact the District Manager and request approval in your APD or APM. Your request must include a report from an independent third party on the equipment's design and suitability for its intended use as well as any other information required by the District Manager. The District Manager may impose any conditions regarding the equipment's capabilities, operation, and testing.

(n) You have pipe/variable bore rams that have no current utility or well-control purposes; Indicate in your APD or APM which pipe/variable bore rams meet these criteria and clearly label them on all BOP control panels. You do not need to function test or pressure test pipe/variable bore rams having no current utility, and that will not be used for well-control purposes, until such time as they are intended to be used during operations.

(o) You install redundant components for well control in your BOP system that are in addition to the required components of this subpart (e.g., pipe/variable bore rams, shear rams, annular preventers, gas bleed lines, and choke/kill side outlets or lines); Comply with all testing, maintenance, and inspection requirements in this subpart that are applicable to those well-control components. If any redundant component fails a test, you must submit a report from an independent third party that describes the failure and confirms that there is no impact on the BOP that will make it unfit for well-control purposes. You must submit this report to the District Manager and receive approval before resuming operations. The District Manager may require you to provide additional information as needed to clarify or evaluate your report.

(p) Need to position the bottom hole assembly, including heavy-weight pipe or collars, and bottom-hole tools across the BOP for tripping or any other operations. Ensure that the well is stable prior to positioning the bottom hole assembly across the BOP. You must have, as part of your well-control plan required by §250.710, procedures that enable the removal of the bottom hole assembly from across the BOP in the event of a well-control or emergency situation (for dynamically positioned rigs, your plan must also include steps for when the EDS must be activated) before MASP conditions are reached as defined for the operation.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21983, May 15, 2019]

§250.739 What are the BOP maintenance and inspection requirements?

(a) You must maintain and inspect your BOP system to ensure that the equipment functions as designed. The BOP maintenance and inspections must meet or exceed any OEM recommendations, recognized engineering practices, and industry standards incorporated by reference into the regulations of this subpart, including API Standard 53 (incorporated by reference in §250.198). You must document how you met or exceeded the provisions of API Standard 53, maintain complete records to ensure the traceability of BOP stack equipment beginning at fabrication, and record the results of your BOP inspections and maintenance actions. You must make all records available to BSEE upon request.

(b) A major, detailed inspection of the well control system components (including but not limited to riser, BOP, LMRP, and control pods) must be performed every 5 years. This major inspection may be performed in phased intervals. You must track and document all system and component inspection dates. These records must be available on the rig. An independent third party is required to review the inspection results and must compile a detailed report of the inspection results, including descriptions of any problems and how they were corrected. You must make these reports available to BSEE upon request. This major inspection must be performed every 5 years from the following applicable dates, whichever is later:

(1) The date the equipment owner accepts delivery of a new build drilling rig with a new BOP system;

(2) The date the new, repaired, or remanufactured equipment is initially installed into the system; or

(3) The date of the last 5 year inspection for the component.

(c) You must visually inspect your surface BOP system on a daily basis. You must visually inspect your subsea BOP system, marine riser, and wellhead at least once every 3 days if weather and sea conditions permit. You may use cameras to inspect subsea equipment.

(d) You must ensure that all personnel maintaining, inspecting, or repairing BOPs, or critical components of the BOP system, are trained in accordance with applicable training requirements in subpart S of this part, any applicable OEM criteria, recognized engineering practices, and industry standards incorporated by reference in this subpart.

(e) You must make all records available to BSEE upon request. You must ensure that the rig unit owner maintains the BOP maintenance, inspection, and repair records on the rig unit for 2 years from the date the records are created or for a longer period if directed by BSEE. You must ensure that all equipment schematics, maintenance, inspection, and repair records are located at an onshore location for the service life of the equipment.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21983, May 15, 2019]

Records and Reporting

§250.740 What records must I keep?

You must keep a daily report consisting of complete, legible, and accurate records for each well. You must keep records onsite while well operations continue. After completion of operations, you must keep all operation and other well records for the time periods shown in §250.741 at a location of your choice, except as required in §250.746. The records must contain complete information on all of the following:

(a) Well operations, all testing conducted, and any real-time monitoring data as required by §250.724;

(b) Descriptions of formations penetrated;

(c) Content and character of oil, gas, water, and other mineral deposits in each formation;

(d) Kind, weight, size, grade, and setting depth of casing;

(e) All well logs and surveys run in the wellbore;

(f) Any significant malfunction or problem; and

(g) All other information required by the District Manager as appropriate to ensure compliance with the requirements of this section and to enable BSEE to determine that the well operations are consistent with conservation of natural resources and protection of safety and the environment on the OCS.

§250.741 How long must I keep records?

You must keep records for the time periods shown in the following table.

You must keep records relating to . . .	Until . . .
(a) Drilling;	90 days after you complete operations.
(b) Casing and liner pressure tests, diverter tests, BOP tests, and real-time monitoring data;	2 years after the completion of operations.
(c) Completion of a well or of any workover activity that materially alters the completion configuration or affects a hydrocarbon-bearing zone.	You permanently plug and abandon the well or until you assign the lease and forward the records to the assignee.

§250.742 What well records am I required to submit?

You must submit to BSEE copies of logs or charts of electrical, radioactive, sonic, and other well logging operations; directional and vertical well surveys; velocity profiles and surveys; and analysis of cores. Each Region will provide specific instructions for submitting well logs and surveys.

§250.743 What are the well activity reporting requirements?

(a) For operations in the BSEE Gulf of Mexico (GOM) OCS Region, you must submit Form BSEE-0133, Well Activity Report (WAR), to the District Manager on a weekly basis. The reporting week is defined as beginning on Sunday (12 a.m.) and ending on the following Saturday (11:59 p.m.). This reporting week corresponds to a week (Sunday through Saturday) on a standard calendar. Report any well operations that extend past the end of this weekly reporting period on the next weekly report. The reporting period for the weekly report is never longer than 7 days, but could be less than 7 days for the first reporting period and the last reporting period for a particular well operation. Submit each WAR and accompanying Form BSEE-0133S, Open Hole Data Report, to the BSEE GOM OCS Region no later than close of business on the Friday immediately after the closure of the reporting week. The District Manager may require more frequent submittal of the WAR on a case-by-case basis.

(b) For operations in the Pacific or Alaska OCS Regions, you must submit Form BSEE-0133, WAR, to the District Manager on a daily basis.

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

§250.744 What are the end of operation reporting requirements?

(a) Within 30 days after completing operations, except routine operations as defined in §250.601, you must submit Form BSEE-0125, End of Operations Report (EOR), to the District Manager. The EOR must include: a listing, with top and bottom depths, of all hydrocarbon zones and other zones of porosity encountered with any cored intervals; details on any drill-stem and formation tests conducted; documentation of successful negative pressure testing on wells that use a subsea BOP stack or wells with mudline suspension systems; and an updated schematic of the full wellbore configuration. The schematic must be clearly labeled and show all applicable top and bottom depths, locations and sizes of all casings, cut casing or stubs, casing perforations, casing rupture discs (indicate if burst or collapse and rating), cemented intervals, cement plugs, mechanical plugs, perforated zones, completion equipment, production and isolation packers, alternate completions, tubing, landing nipples, subsurface safety devices, and any other information required by the District Manager regarding the end of well operations. The EOR must indicate the status of the well (completed, temporarily abandoned, permanently abandoned, or drilling suspended) and the date of the well status designation. The well status date is subject to the following:

(1) For surface well operations and riserless subsea operations, the operations end date is subject to the discretion of the District Manager; and

(2) For subsea well operations, the operations end date is considered to be the date the BOP is disconnected from the wellhead unless otherwise specified by the District Manager.

(b) You must submit public information copies of Form BSEE-0125 according to §250.186(b).

§250.745 What other well records could I be required to submit?

The District Manager or Regional Supervisor may require you to submit copies of any or all of the following well records:

(a) Well records as specified in §250.740;

(b) Paleontological interpretations or reports identifying microscopic fossils by depth and/or washed samples of drill cuttings that you normally maintain for paleontological determinations. The Regional Supervisor may issue a Notice to Lessees that sets forth the manner, timeframe, and format for submitting this information;

(c) Service company reports on cementing, perforating, acidizing, testing, or other similar services; or

(d) Other reports and records of operations.

§250.746 What are the recordkeeping requirements for casing, liner, and BOP tests, and inspections of BOP systems and marine risers?

You must record the time, date, and results of all casing and liner pressure tests. You must also record pressure tests, actuations, and inspections of the BOP system, system components, and marine riser in the daily report described in §250.740. In addition, you must:

(a) Record test pressures on pressure charts or digital recorders;

(b) Require your onsite lessee representative, designated rig or contractor representative, and pump operator to sign and date the pressure charts or digital recordings and daily reports as correct;

(c) Document on the daily report the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. For subsea BOP systems, you must also record the closing times for annular and ram BOPs. You may reference a BOP test plan if it is available at the facility;

(d) Identify on the daily report the control station and pod used during the test (identifying the pod does not apply to coiled tubing and snubbing units);

(e) Identify on the daily report any problems or irregularities observed during BOP system testing and record actions taken to remedy the problems or irregularities. Any leaks associated with the BOP or control system during testing must be documented in the WAR. If any problems that cannot be resolved promptly are observed during testing, operations must be suspended until the District Manager determines that you may continue; and

(f) Retain all records, including pressure charts, daily reports, and referenced documents pertaining to tests, actuations, and inspections at the rig unit for the duration of the operation. After completion of the operation, you must retain all the records listed in this section for a period of 2 years at the rig unit. You must also retain the records at the lessee's field office nearest the facility or at another location available to BSEE. You must make all the records available to BSEE upon request.

Coiled Tubing Operations

§250.750 What are the coiled tubing requirements?

(a) For coiled tubing operations, you must follow the applicable requirements of this subpart and you must meet the following minimum requirements for the BOP system:

(1) BOP system components must be in the following order from the top down:

BOP system when expected surface pressures are less than or equal to 3,500 psi BOP system when expected surface pressures are greater than 3,500 psi BOP system for wells with returns taken through an outlet on the BOP stack

(i) Stripper or annular-type well control component Stripper or annular-type well control component Stripper or annular-type well control component.

(ii) Hydraulically-operated blind rams Hydraulically-operated blind rams Hydraulically-operated blind rams.

(iii) Hydraulically-operated shear rams Hydraulically-operated shear rams Hydraulically-operated shear rams.

(iv) Kill line inlet Kill line inlet Kill line inlet.

(v) Hydraulically-operated two-way slip rams Hydraulically-operated two-way slip rams Hydraulically-operated two-way slip rams.

Hydraulically-operated pipe rams.

(vi) Hydraulically-operated pipe rams Hydraulically-operated pipe rams

Hydraulically-operated blind-shear rams. These rams should be located as close to the tree as practical A flow tee or cross.

Hydraulically-operated pipe rams.

Hydraulically-operated blind-shear rams on wells with surface pressures >3,500 psi. As an option, the pipe rams can be placed below the blind-shear rams. The blind-shear rams should be located as close to the tree as practical.

(2) You may use a set of hydraulically-operated combination rams for the blind rams and shear rams.

(3) You may use a set of hydraulically-operated combination rams for the hydraulic two-way slip rams and the hydraulically-operated pipe rams.

(4) You must attach a dual check valve assembly to the coiled tubing connector at the downhole end of the coiled tubing string for all coiled tubing operations. If you plan to conduct operations without downhole check valves, you must describe alternate procedures and equipment in Form BSEE-0124, Application for Permit to Modify and have it approved by the District Manager.

(5) You must have a kill line and a separate choke line. You must equip each line with two full-opening valves and at least one of the valves must be remotely controlled. You may use a manual valve instead of the remotely controlled valve on the kill line if you install a check valve between the two full-opening manual valves and the pump or manifold. The valves must have a working pressure rating equal to or greater than the working pressure rating of the connection to which they are attached, and you must

install them between the well control stack and the choke or kill line. For operations with expected surface pressures greater than 3,500 psi, the kill line must be connected to a pump or manifold. You must not use the kill line inlet on the BOP stack for taking fluid returns from the wellbore.

(6) You must have a hydraulic-actuating system that provides sufficient accumulator capacity to close-open-close each component in the BOP stack. This cycle must be completed with at least 200 psi above the pre-charge pressure, without assistance from a charging system.

(7) All connections used in the surface BOP system from the tree to the uppermost required ram must be flanged, including the connections between the well control stack and the first full-opening valve on the choke line and the kill line.

(b) BSEE considers all coiled tubing operations to be non-routine.

[84 FR 21983, May 15, 2019]

§250.751 Coiled tubing testing requirements.

You must test the coiled tubing unit in accordance with §250.737(a), (b), (c), (d)(9), and (d)(10). You must successfully pressure test the dual check valves to the rated working pressure of the connector, the rated working pressure of the dual check valve, expected surface pressure, or the collapse pressure of the coiled tubing, whichever is less. The test interval for coiled tubing operations must include a 10 minute high-pressure test for the coiled tubing string.

[84 FR 21984, May 15, 2019]

Snubbing Operations

§250.760   What are the snubbing requirements?

(a) For snubbing operations, you must follow the applicable requirements of this subpart and have the following minimum BOP-system components:

(1) One set of pipe rams hydraulically operated,

(2) Two sets of stripper-type pipe rams hydraulically operated with spacer spool,

(3) An inside BOP or a spring-loaded, back-pressure safety valve in the open position located on the rig floor, and

(4) An essentially full-opening, work-string safety valve in the open position must be maintained on the rig floor at all times and a wrench to fit the work-string safety valve must be readily available.

(5) Proper connections must be readily available for inserting valves in the work string.

(b) Test the snubbing unit in accordance with §250.737(a), (b), and (c).

[84 FR 21984, May 15, 2019]