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Title 30: Mineral Resources

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

Subpart D—Oil and Gas Drilling Operations

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GENERAL REQUIREMENTS

§250.400 General requirements.

Drilling operations must be conducted in a safe manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the Outer Continental Shelf (OCS), including any mineral deposits (in areas leased and not leased), the National security or defense, or the marine, coastal, or human environment. In addition to the requirements of this subpart, you must also follow the applicable requirements of subpart G of this part.

[81 FR 26017, Apr. 29, 2016]

§§250.401-250.403 [Reserved]

§250.404 What are the requirements for the crown block?

You must have a crown block safety device that prevents the traveling block from striking the crown block. You must check the device for proper operation at least once per week and after each drill-line slipping operation and record the results of this operational check in the driller's report.

§250.405 What are the safety requirements for diesel engines used on a drilling rig?

You must equip each diesel engine with an air intake device to shut down the diesel engine in the event of a runaway.

(a) For a diesel engine that is not continuously manned, you must equip the engine with an automatic shutdown device;

(b) For a diesel engine that is continuously manned, you may equip the engine with either an automatic or remote manual air intake shutdown device;

(c) You do not have to equip a diesel engine with an air intake device if it meets one of the following criteria:

- (1) Starts a larger engine;
- (2) Powers a firewater pump;
- (3) Powers an emergency generator;
- (4) Powers a BOP accumulator system;
- (5) Provides air supply to divers or confined entry personnel;
- (6) Powers temporary equipment on a nonproducing platform;
- (7) Powers an escape capsule; or
- (8) Powers a portable single-cylinder rig washer.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36149, June 6, 2016]

§250.406 [Reserved]

§250.407 What tests must I conduct to determine reservoir characteristics?

You must determine the presence, quantity, quality, and reservoir characteristics of oil, gas, sulphur, and water in the formations penetrated by logging, formation sampling, or well testing.

§250.408 May I use alternative procedures or equipment during drilling operations?

You may use alternative procedures or equipment during drilling operations after receiving approval from the District Manager. You must identify and discuss your proposed alternative procedures or equipment in your Application for Permit to Drill (APD) (Form BSEE-0123) (see §250.414(h)). Procedures for obtaining approval are described in §250.141 of this part.

§250.409 May I obtain departures from these drilling requirements?

The District Manager may approve departures from the drilling requirements specified in this subpart. You may apply for a departure from drilling requirements by writing to the District Manager. You should identify and discuss the departure you are requesting in your APD (see §250.414(h)).

APPLYING FOR A PERMIT TO DRILL

§250.410 How do I obtain approval to drill a well?

You must obtain written approval from the District Manager before you begin drilling any well or

before you sidetrack, bypass, or deepen a well. To obtain approval, you must:

- (a) Submit the information required by §§250.411 through 250.418;
- (b) Include the well in your approved Exploration Plan (EP), Development and Production Plan (DPP), or Development Operations Coordination Document (DOCD);
- (c) Meet the oil spill financial responsibility requirements for offshore facilities as required by 30 CFR part 553; and
- (d) Submit the following to the District Manager:
 - (1) An original and two complete copies of Form BSEE-0123, Application for Permit to Drill (APD), and Form BSEE-0123S, Supplemental APD Information Sheet;
 - (2) A separate public information copy of forms BSEE-0123 and BSEE-0123S that meets the requirements of §250.186; and
 - (3) Payment of the service fee listed in §250.125.

§250.411 What information must I submit with my application?

In addition to forms BSEE-0123 and BSEE-0123S, you must include the information required in this subpart and subpart G of this part, including the following:

Information that you must include with an APD	Where to find a description
(a) Plat that shows locations of the proposed well,	§250.412.
(b) Design criteria used for the proposed well,	§250.413.
(c) Drilling prognosis,	§250.414.
(d) Casing and cementing programs,	§250.415.
(e) Diverter systems descriptions,	§250.416.
(f) BOP system descriptions,	§250.731.
(g) Requirements for using a MODU, and	§250.713.
(h) Additional information.	§250.418.

[81 FR 26017, Apr. 29, 2016]

§250.412 What requirements must the location plat meet?

The location plat must:

- (a) Have a scale of 1:24,000 (1 inch = 2,000 feet);
- (b) Show the surface and subsurface locations of the proposed well and all the wells in the vicinity;
- (c) Show the surface and subsurface locations of the proposed well in feet or meters from the block line;
- (d) Contain the longitude and latitude coordinates, and either Universal Transverse Mercator grid-system coordinates or state plane coordinates in the Lambert or Transverse Mercator Projection system

for the surface and subsurface locations of the proposed well; and

(e) State the units and geodetic datum (including whether the datum is North American Datum 27 or 83) for these coordinates. If the datum was converted, you must state the method used for this conversion, since the various methods may produce different values.

§250.413 What must my description of well drilling design criteria address?

Your description of well drilling design criteria must address:

- (a) Pore pressures;
- (b) Formation fracture gradients, adjusted for water depth;
- (c) Potential lost circulation zones;
- (d) Drilling fluid weights;
- (e) Casing setting depths;

(f) Maximum anticipated surface pressures. For this section, maximum anticipated surface pressures are the pressures that you reasonably expect to be exerted upon a casing string and its related wellhead equipment. In calculating maximum anticipated surface pressures, you must consider: drilling, completion, and producing conditions; drilling fluid densities to be used below various casing strings; fracture gradients of the exposed formations; casing setting depths; total well depth; formation fluid types; safety margins; and other pertinent conditions. You must include the calculations used to determine the pressures for the drilling and the completion phases, including the anticipated surface pressure used for designing the production string;

(g) A single plot containing curves for estimated pore pressures, formation fracture gradients, proposed drilling fluid weights, planned safe drilling margin, and casing setting depths in true vertical measurements;

(h) A summary report of the shallow hazards site survey that describes the geological and manmade conditions if not previously submitted; and

- (i) Permafrost zones, if applicable.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26017, Apr. 29, 2016]

§250.414 What must my drilling prognosis include?

Your drilling prognosis must include a brief description of the procedures you will follow in drilling the well. This prognosis includes but is not limited to the following:

- (a) Projected plans for coring at specified depths;
- (b) Projected plans for logging;

(c) Planned safe drilling margin that is between the estimated pore pressure and the lesser of estimated fracture gradients or casing shoe pressure integrity test and that is based on a risk assessment consistent with expected well conditions and operations.

- (1) Your safe drilling margin must also include use of equivalent downhole mud weight that is:

(i) Greater than the estimated pore pressure; and

(ii) Except as provided in paragraph (c)(2) of this section, a minimum of 0.5 pound per gallon below the lower of the casing shoe pressure integrity test or the lowest estimated fracture gradient.

(2) In lieu of meeting the criteria in paragraph (c)(1)(ii) of this section, you may use an equivalent downhole mud weight as specified in your APD, provided that you submit adequate documentation (such as risk modeling data, off-set well data, analog data, seismic data) to justify the alternative equivalent downhole mud weight.

(3) When determining the pore pressure and lowest estimated fracture gradient for a specific interval, you must consider related off-set well behavior observations.

(d) Estimated depths to the top of significant marker formations;

(e) Estimated depths to significant porous and permeable zones containing fresh water, oil, gas, or abnormally pressured formation fluids;

(f) Estimated depths to major faults;

(g) Estimated depths of permafrost, if applicable;

(h) A list and description of all requests for using alternate procedures or departures from the requirements of this subpart in one place in the APD. You must explain how the alternate procedures afford an equal or greater degree of protection, safety, or performance, or why the departures are requested;

(i) Projected plans for well testing (refer to §250.460);

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

(k) Any additional information required by the District Manager needed to clarify or evaluate your drilling prognosis.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26017, Apr. 29, 2016]

§250.415 What must my casing and cementing programs include?

Your casing and cementing programs must include:

(a) The following well design information:

(1) Hole sizes;

(2) Bit depths (including measured and true vertical depth (TVD));

(3) Casing information, including sizes, weights, grades, collapse and burst values, types of connection, and setting depths (measured and TVD) for all sections of each casing interval; and

(4) Locations of any installed rupture disks (indicate if burst or collapse and rating);

(b) Casing design safety factors for tension, collapse, and burst with the assumptions made to arrive at these values;

(c) Type and amount of cement (in cubic feet) planned for each casing string;

(d) In areas containing permafrost, setting depths for conductor and surface casing based on the anticipated depth of the permafrost. Your program must provide protection from thaw subsidence and freezeback effect, proper anchorage, and well control;

(e) A statement of how you evaluated the best practices included in API RP 65, Recommended Practice for Cementing Shallow Water Flow Zones in Deep Water Wells (as incorporated by reference in §250.198), if you drill a well in water depths greater than 500 feet and are in either of the following two areas:

(1) An “area with an unknown shallow water flow potential” is a zone or geologic formation where neither the presence nor absence of potential for a shallow water flow has been confirmed.

(2) An “area known to contain a shallow water flow hazard” is a zone or geologic formation for which drilling has confirmed the presence of shallow water flow; and

(f) A written description of how you evaluated the best practices included in API Standard 65—Part 2, Isolating Potential Flow Zones During Well Construction, Second Edition (as incorporated by reference in §250.198). Your written description must identify the mechanical barriers and cementing practices you will use for each casing string (reference API Standard 65—Part 2, Sections 4 and 5).

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50891, Aug. 22, 2012; 81 FR 26018, Apr. 29, 2016]

§250.416 What must I include in the diverter description?

You must include in the diverter description:

(a) A description of the diverter system and its operating procedures;

(b) A schematic drawing of the diverter system (plan and elevation views) that shows:

(1) The size of the element installed in the diverter housing;

(2) Spool outlet internal diameter(s);

(3) Diverter-line lengths and diameters; burst strengths and radius of curvature at each turn; and

(4) Valve type, size, working pressure rating, and location.

[81 FR 26018, Apr. 29, 2016]

§250.417 [Reserved]

§250.418 What additional information must I submit with my APD?

You must include the following with the APD:

(a) Rated capacities of the drilling rig and major drilling equipment, if not already on file with the appropriate District office;

(b) A drilling fluids program that includes the minimum quantities of drilling fluids and drilling fluid materials, including weight materials, to be kept at the site;

(c) A proposed directional plot if the well is to be directionally drilled;

(d) A Hydrogen Sulfide Contingency Plan (see §250.490), if applicable, and not previously submitted;

(e) A welding plan (see §§250.109 to 250.113) if not previously submitted;

(f) In areas subject to subfreezing conditions, evidence that the drilling equipment, BOP systems and components, diverter systems, and other associated equipment and materials are suitable for operating under such conditions;

(g) A request for approval, if you plan to wash out or displace cement to facilitate casing removal upon well abandonment. Your request must include a description of how far below the mudline you propose to displace cement and how you will visually monitor returns;

(h) Certification of your casing and cementing program as required in §250.420(a)(7); and

(i) Such other information as the District Manager may require.

(j) For Arctic OCS exploratory drilling operations, you must provide the information required by §250.470.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50892, Aug. 22, 2012; 81 FR 26018, Apr. 29, 2016; 81 FR 46561, July 15, 2016]

CASING AND CEMENTING REQUIREMENTS

§250.420 What well casing and cementing requirements must I meet?

You must case and cement all wells. Your casing and cementing programs must meet the applicable requirements of this subpart and of subpart G of this part.

(a) *Casing and cementing program requirements.* Your casing and cementing programs must:

(1) Properly control formation pressures and fluids;

(2) Prevent the direct or indirect release of fluids from any stratum through the wellbore into offshore waters;

(3) Prevent communication between separate hydrocarbon-bearing strata;

(4) Protect freshwater aquifers from contamination;

(5) Support unconsolidated sediments;

(6) Provide adequate centralization to ensure proper cementation; and

(7)(i) Include a certification signed by a registered professional engineer that the casing and cementing design is appropriate for the purpose for which it is intended under expected wellbore conditions, and is sufficient to satisfy the tests and requirements of this section and §250.423. Submit this certification with your APD (Form BSEE-0123).

(ii) You must have the registered professional engineer involved in the casing and cementing design process.

(iii) The registered professional engineer must be registered in a state of the United States and have sufficient expertise and experience to perform the certification.

(b) *Casing requirements.* (1) You must design casing (including liners) to withstand the anticipated stresses imposed by tensile, compressive, and buckling loads; burst and collapse pressures; thermal effects; and combinations thereof.

(2) The casing design must include safety measures that ensure well control during drilling and safe operations during the life of the well.

(3) On all wells that use subsea BOP stacks, you must include two independent barriers, including one mechanical barrier, in each annular flow path (examples of barriers include, but are not limited to, primary cement job and seal assembly). For the final casing string (or liner if it is your final string), you must install one mechanical barrier in addition to cement to prevent flow in the event of a failure in the cement. A dual float valve, by itself, is not considered a mechanical barrier. These barriers cannot be modified prior to or during completion or abandonment operations. The BSEE District Manager may approve alternative options under §250.141. You must submit documentation of this installation to BSEE in the End-of-Operations Report (Form BSEE-0125).

(4) If you need to substitute a different size, grade, or weight of casing than what was approved in your APD, you must contact the District Manager for approval prior to installing the casing.

(c) *Cementing requirements.* (1) You must design and conduct your cementing jobs so that cement composition, placement techniques, and waiting times ensure that the cement placed behind the bottom 500 feet of casing attains a minimum compressive strength of 500 psi before drilling out the casing or before commencing completion operations. (If a liner is used refer to §250.421(f)).

(2) You must use a weighted fluid during displacement to maintain an overbalanced hydrostatic pressure during the cement setting time, except when cementing casings or liners in riserless hole sections.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50892, Aug. 22, 2012; 81 FR 26018, Apr. 29, 2016]

§250.421 What are the casing and cementing requirements by type of casing string?

The table in this section identifies specific design, setting, and cementing requirements for casing strings and liners. For the purposes of subpart D, the casing strings in order of normal installation are as follows: drive or structural, conductor, surface, intermediate, and production casings (including liners). The District Manager may approve or prescribe other casing and cementing requirements where appropriate.

Casing type	Casing requirements	Cementing requirements
(a) Drive or Structural	Set by driving, jetting, or drilling to the minimum depth as approved or prescribed by the District Manager	If you drilled a portion of this hole, you must use enough cement to fill the annular space back to the mudline.
(b) Conductor	Design casing and select setting depths based on relevant engineering and geologic factors. These factors include the presence or absence of hydrocarbons, potential hazards, and water depths Set casing immediately before drilling into formations known to contain oil or gas. If you encounter oil or gas or unexpected formation pressure before the planned casing point, you must set casing immediately and set it above the encountered zone	Use enough cement to fill the calculated annular space back to the mudline. Verify annular fill by observing cement returns. If you cannot observe cement returns, use additional cement to ensure fill-back to the mudline. For drilling on an artificial island or when using a well cellar, you must discuss the cement fill level with the District Manager.
(c) Surface	Design casing and select setting	Use enough cement to fill the calculated annular

	depths based on relevant engineering and geologic factors. These factors include the presence or absence of hydrocarbons, potential hazards, and water depths	space to at least 200 feet inside the conductor casing. When geologic conditions such as near-surface fractures and faulting exist, you must use enough cement to fill the calculated annular space to the mudline.
(d) Intermediate	Design casing and select setting depth based on anticipated or encountered geologic characteristics or wellbore conditions	Use enough cement to cover and isolate all hydrocarbon-bearing zones and isolate abnormal pressure intervals from normal pressure intervals in the well. As a minimum, you must cement the annular space 500 feet above the casing shoe and 500 feet above each zone to be isolated.
(e) Production	Design casing and select setting depth based on anticipated or encountered geologic characteristics or wellbore conditions	Use enough cement to cover or isolate all hydrocarbon-bearing zones above the shoe. As a minimum, you must cement the annular space at least 500 feet above the casing shoe and 500 feet above the uppermost hydrocarbon-bearing zone.
(f) Liners	If you use a liner as surface casing, you must set the top of the liner at least 200 feet above the previous casing/liner shoe If you use a liner as an intermediate string below a surface string or production casing below an intermediate string, you must set the top of the liner at least 100 feet above the previous casing shoe You may not use a liner as conductor casing A subsea well casing string whose top is above the mudline and that has been cemented back to the mudline will not be considered a liner	Same as cementing requirements for specific casing types. For example, a liner used as intermediate casing must be cemented according to the cementing requirements for intermediate casing. If you have a liner lap and are unable to cement 500 feet above the previous shoe, as provided by paragraphs (d) and (e) of this section, you must submit and receive approval from the District Manager on a case-by-case basis.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26018, Apr. 29, 2016]

§250.422 When may I resume drilling after cementing?

(a) After cementing surface, intermediate, or production casing (or liners), you may resume drilling after the cement has been held under pressure for 12 hours. For conductor casing, you may resume drilling after the cement has been held under pressure for 8 hours. One acceptable method of holding cement under pressure is to use float valves to hold the cement in place.

(b) If you plan to nipple down your diverter or BOP stack during the 8- or 12-hour waiting time, you must determine, before nipping down, when it will be safe to do so. You must base your determination on a knowledge of formation conditions, cement composition, effects of nipping down, presence of potential drilling hazards, well conditions during drilling, cementing, and post cementing, as well as past experience.

§250.423 What are the requirements for casing and liner installation?

You must ensure proper installation of casing in the subsea wellhead or liner in the liner hanger.

(a) You must ensure that the latching mechanisms or lock down mechanisms are engaged upon successfully installing and cementing the casing string. If there is an indication of an inadequate cement

job, you must comply with §250.428(c).

(b) If you run a liner that has a latching mechanism or lock down mechanism, you must ensure that the latching mechanisms or lock down mechanisms are engaged upon successfully installing and cementing the liner. If there is an indication of an inadequate cement job, you must comply with §250.428(c).

(c) You must perform a pressure test on the casing seal assembly to ensure proper installation of casing or liner. You must perform this test for the intermediate and production casing strings or liners.

(1) You must submit for approval with your APD, test procedures and criteria for a successful test.

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

[81 FR 26019, Apr. 29, 2016]

§§250.424-250.426 [Reserved]

§250.427 What are the requirements for pressure integrity tests?

You must conduct a pressure integrity test below the surface casing or liner and all intermediate casings or liners. The District Manager may require you to run a pressure-integrity test at the conductor casing shoe if warranted by local geologic conditions or the planned casing setting depth. You must conduct each pressure integrity test after drilling at least 10 feet but no more than 50 feet of new hole below the casing shoe. You must test to either the formation leak-off pressure or to an equivalent drilling fluid weight if identified in an approved APD.

(a) You must use the pressure integrity test and related hole-behavior observations, such as pore-pressure test results, gas-cut drilling fluid, and well kicks to adjust the drilling fluid program and the setting depth of the next casing string. You must record all test results and hole-behavior observations made during the course of drilling related to formation integrity and pore pressure in the driller's report.

(b) While drilling, you must maintain the safe drilling margins identified in §250.414. When you cannot maintain the safe margins, you must suspend drilling operations and remedy the situation.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26019, Apr. 29, 2016]

§250.428 What must I do in certain cementing and casing situations?

The table in this section describes actions that lessees must take when certain situations occur during casing and cementing activities.

If you encounter the following situation:	Then you must . . .
(a) Have unexpected formation pressures or conditions that warrant revising your casing design,	Submit a revised casing program to the District Manager for approval.
(b) Need to change casing setting depths or hole interval drilling depth (for a BHA with an under-reamer, this means bit depth) more than 100 feet true vertical depth (TVD) from the approved APD due to conditions encountered during drilling operations,	Submit those changes to the District Manager for approval and include a certification by a professional engineer (PE) that he or she reviewed and approved the proposed changes.
(c) Have indication of inadequate cement job (such as lost returns, no cement returns to mudline or expected height, cement	(1) Locate the top of cement by: (i) Running a temperature survey; (ii) Running a cement evaluation log; or

channeling, or failure of equipment),	(iii) Using a combination of these techniques. (2) Determine if your cement job is inadequate. If your cement job is determined to be inadequate, refer to paragraph (d) of this section. (3) If your cement job is determined to be adequate, report the results to the District Manager in your submitted WAR.
(d) Inadequate cement job,	Take remedial actions. The District Manager must review and approve all remedial actions before you may take them, unless immediate actions must be taken to ensure the safety of the crew or to prevent a well-control event. If you complete any immediate action to ensure the safety of the crew or to prevent a well-control event, submit a description of the action to the District Manager when that action is complete. Any changes to the well program will require submittal of a certification by a professional engineer (PE) certifying that he or she reviewed and approved the proposed changes, and must meet any other requirements of the District Manager.
(e) Primary cement job that did not isolate abnormal pressure intervals,	Isolate those intervals from normal pressures by squeeze cementing before you complete; suspend operations; or abandon the well, whichever occurs first.
(f) Decide to produce a well that was not originally contemplated for production,	Have at least two cemented casing strings (does not include liners) in the well. Note: All producing wells must have at least two cemented casing strings.
(g) Want to drill a well without setting conductor casing,	Submit geologic data and information to the District Manager that demonstrates the absence of shallow hydrocarbons or hazards. This information must include logging and drilling fluid-monitoring from wells previously drilled within 500 feet of the proposed well path down to the next casing point.
(h) Need to use less than required cement for the surface casing during floating drilling operations to provide protection from burst and collapse pressures,	Submit information to the District Manager that demonstrates the use of less cement is necessary.
(i) Cement across a permafrost zone,	Use cement that sets before it freezes and has a low heat of hydration.
(j) Leave the annulus opposite a permafrost zone uncemented,	Fill the annulus with a liquid that has a freezing point below the minimum permafrost temperature and minimizes opposite a corrosion.
(k) Plan to use a valve(s) on the drive pipe during cementing operations for the conductor casing, surface casing, or liner,	Include a description of the plan in your APD. Your description must include a schematic of the valve and height above the water line. The valve must be remotely operated and full opening with visual observation while taking returns. The person in charge of observing returns must be in communication with the drill floor. You must record in your daily report and in the WAR if cement returns were observed. If cement returns are not observed, you must contact the District Manager and obtain approval of proposed plans to locate the top of cement before continuing with operations.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50892, Aug. 22, 2012; 81 FR 26019, Apr. 29, 2016]

DIVERTER SYSTEM REQUIREMENTS

§250.430 When must I install a diverter system?

You must install a diverter system before you drill a conductor or surface hole. The diverter system consists of a diverter sealing element, diverter lines, and control systems. You must design, install, use, maintain, and test the diverter system to ensure proper diversion of gases, water, drilling fluid, and other materials away from facilities and personnel.

§250.431 What are the diverter design and installation requirements?

You must design and install your diverter system to:

- (a) Use diverter spool outlets and diverter lines that have a nominal diameter of at least 10 inches for surface wellhead configurations and at least 12 inches for floating drilling operations;
- (b) Use dual diverter lines arranged to provide for downwind diversion capability;
- (c) Use at least two diverter control stations. One station must be on the drilling floor. The other station must be in a readily accessible location away from the drilling floor;
- (d) Use only remote-controlled valves in the diverter lines. All valves in the diverter system must be full-opening. You may not install manual or butterfly valves in any part of the diverter system;
- (e) Minimize the number of turns (only one 90-degree turn allowed for each line for bottom-founded drilling units) in the diverter lines, maximize the radius of curvature of turns, and target all right angles and sharp turns;
- (f) Anchor and support the entire diverter system to prevent whipping and vibration; and
- (g) Protect all diverter-control instruments and lines from possible damage by thrown or falling objects.

§250.432 How do I obtain a departure to diverter design and installation requirements?

The table below describes possible departures from the diverter requirements and the conditions required for each departure. To obtain one of these departures, you must have discussed the departure in your APD and received approval from the District Manager.

If you want a departure to:	Then you must . . .
(a) Use flexible hose for diverter lines instead of rigid pipe,	Use flexible hose that has integral end couplings.
(b) Use only one spool outlet for your diverter system,	(1) Have branch lines that meet the minimum internal diameter requirements; and (2) Provide downwind diversion capability.
(c) Use a spool with an outlet with an internal diameter of less than 10 inches on a surface wellhead,	Use a spool that has dual outlets with an internal diameter of at least 8 inches.
(d) Use a single diverter line for floating drilling operations on a dynamically positioned drillship,	Maintain an appropriate vessel heading to provide for downwind diversion.

§250.433 What are the diverter actuation and testing requirements?

When you install the diverter system, you must actuate the diverter sealing element, diverter valves, and diverter-control systems and control stations. You must also flow-test the vent lines.

(a) For drilling operations with a surface wellhead configuration, you must actuate the diverter system at least once every 24-hour period after the initial test. After you have nipped up on conductor casing, you must pressure-test the diverter-sealing element and diverter valves to a minimum of 200 psi. While the diverter is installed, you must conduct subsequent pressure tests within 7 days after the previous test.

(b) For floating drilling operations with a subsea BOP stack, you must actuate the diverter system within 7 days after the previous actuation.

(c) You must alternate actuations and tests between control stations.

§250.434 What are the recordkeeping requirements for diverter actuations and tests?

You must record the time, date, and results of all diverter actuations and tests in the driller's report. In addition, you must:

(a) Record the diverter pressure test on a pressure chart;

(b) Require your onsite representative to sign and date the pressure test chart;

(c) Identify the control station used during the test or actuation;

(d) Identify problems or irregularities observed during the testing or actuations and record actions taken to remedy the problems or irregularities; and

(e) Retain all pressure charts and reports pertaining to the diverter tests and actuations at the facility for the duration of drilling the well.

§§250.440--250.451 [Reserved]

§250.452 What are the real-time monitoring requirements for Arctic OCS exploratory drilling operations?

(a) When conducting exploratory drilling operations on the Arctic OCS, you must gather and monitor real-time 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 fluid handling systems on the rig; and

(3) The well's downhole conditions as monitored by a downhole sensing system, when such a system is installed.

(b) During well operations, you must transmit the data identified in paragraph (a) of this section as they are gathered, barring unforeseeable or unpreventable interruptions in transmission, and have the capability to monitor the data onshore, using qualified personnel. Onshore personnel who monitor real-time data must have the capability to contact rig personnel during operations. After well operations, you must store the data at a designated location for recordkeeping purposes as required in §§250.740 and 250.741. You must provide BSEE with access to your real-time monitoring data onshore upon request.

[81 FR 46561, July 15, 2016]

DRILLING FLUID REQUIREMENTS

§250.455 What are the general requirements for a drilling fluid program?

You must design and implement your drilling fluid program to prevent the loss of well control. This program must address drilling fluid safe practices, testing and monitoring equipment, drilling fluid quantities, and drilling fluid-handling areas.

§250.456 What safe practices must the drilling fluid program follow?

Your drilling fluid program must include the following safe practices:

(a) Before starting out of the hole with drill pipe, you must properly condition the drilling fluid. You must circulate a volume of drilling fluid equal to the annular volume with the drill pipe just off-bottom. You may omit this practice if documentation in the driller's report shows:

(1) No indication of formation fluid influx before starting to pull the drill pipe from the hole;

(2) The weight of returning drilling fluid is within 0.2 pounds per gallon (1.5 pounds per cubic foot) of the drilling fluid entering the hole; and

(3) Other drilling fluid properties are within the limits established by the program approved in the APD.

(b) Record each time you circulate drilling fluid in the hole in the driller's report;

(c) When coming out of the hole with drill pipe, you must fill the annulus with drilling fluid before the hydrostatic pressure decreases by 75 psi, or every five stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. You must calculate the number of stands of drill pipe and drill collars that you may pull before you must fill the hole. You must also calculate the equivalent drilling fluid volume needed to fill the hole. Both sets of numbers must be posted near the driller's station. You must use a mechanical, volumetric, or electronic device to measure the drilling fluid required to fill the hole;

(d) You must run and pull drill pipe and downhole tools at controlled rates so you do not swab or surge the well;

(e) When there is an indication of swabbing or influx of formation fluids, you must take appropriate measures to control the well. You must circulate and condition the well, on or near-bottom, unless well or drilling-fluid conditions prevent running the drill pipe back to the bottom;

(f) You must calculate and post near the driller's console the maximum pressures that you may safely contain under a shut-in BOP for each casing string. The pressures posted must consider the surface pressure at which the formation at the shoe would break down, the rated working pressure of the BOP stack, and 70 percent of casing burst (or casing test as approved by the District Manager). As a minimum, you must post the following two pressures:

(1) The surface pressure at which the shoe would break down. This calculation must consider the current drilling fluid weight in the hole; and

(2) The lesser of the BOP's rated working pressure or 70 percent of casing-burst pressure (or casing test otherwise approved by the District Manager);

(g) You must install an operable drilling fluid-gas separator and degasser before you begin drilling operations. You must maintain this equipment throughout the drilling of the well;

(h) Before pulling drill-stem test tools from the hole, you must circulate or reverse-circulate the test fluids in the hole. If circulating out test fluids is not feasible, you may bullhead test fluids out of the drill-stem test string and tools with an appropriate kill weight fluid;

(i) When circulating, you must test the drilling fluid at least once each tour, or more frequently if

conditions warrant. Your tests must conform to industry-accepted practices and include density, viscosity, and gel strength; hydrogenion concentration; filtration; and any other tests the District Manager requires for monitoring and maintaining drilling fluid quality, prevention of downhole equipment problems and for kick detection. You must record the results of these tests in the drilling fluid report; and

(j) In areas where permafrost and/or hydrate zones are present or may be present, you must control drilling fluid temperatures to drill safely through those zones.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50894, Aug. 22, 2012; 81 FR 26020, Apr. 29, 2016]

§250.457 What equipment is required to monitor drilling fluids?

Once you establish drilling fluid returns, you must install and maintain the following drilling fluid-system monitoring equipment throughout subsequent drilling operations. This equipment must have the following indicators on the rig floor:

(a) Pit level indicator to determine drilling fluid-pit volume gains and losses. This indicator must include both a visual and an audible warning device;

(b) Volume measuring device to accurately determine drilling fluid volumes required to fill the hole on trips;

(c) Return indicator devices that indicate the relationship between drilling fluid-return flow rate and pump discharge rate. This indicator must include both a visual and an audible warning device; and

(d) Gas-detecting equipment to monitor the drilling fluid returns. The indicator may be located in the drilling fluid-logging compartment or on the rig floor. If the indicators are only in the logging compartment, you must continually man the equipment and have a means of immediate communication with the rig floor. If the indicators are on the rig floor only, you must install an audible alarm.

§250.458 What quantities of drilling fluids are required?

(a) You must use, maintain, and replenish quantities of drilling fluid and drilling fluid materials at the drill site as necessary to ensure well control. You must determine those quantities based on known or anticipated drilling conditions, rig storage capacity, weather conditions, and estimated time for delivery.

(b) You must record the daily inventories of drilling fluid and drilling fluid materials, including weight materials and additives in the drilling fluid report.

(c) If you do not have sufficient quantities of drilling fluid and drilling fluid material to maintain well control, you must suspend drilling operations.

§250.459 What are the safety requirements for drilling fluid-handling areas?

You must classify drilling fluid-handling areas according to API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities, Classified as Class I, Division 1 and Division 2 (as incorporated by reference in §250.198); or API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities, Classified as Class 1, Zone 0, Zone 1, and Zone 2 (as incorporated by reference in §250.198). In areas where dangerous concentrations of combustible gas may accumulate, you must install and maintain a ventilation system and gas monitors. Drilling fluid-handling areas must have the following safety equipment:

(a) A ventilation system capable of replacing the air once every 5 minutes or 1.0 cubic feet of air-volume flow per minute, per square foot of area, whichever is greater. In addition:

(1) If natural means provide adequate ventilation, then a mechanical ventilation system is not

necessary;

(2) If a mechanical system does not run continuously, then it must activate when gas detectors indicate the presence of 1 percent or more of combustible gas by volume; and

(3) If discharges from a mechanical ventilation system may be hazardous, then you must maintain the drilling fluid-handling area at a negative pressure. You must protect the negative pressure area by using at least one of the following: a pressure-sensitive alarm, open-door alarms on each access to the area, automatic door-closing devices, air locks, or other devices approved by the District Manager;

(b) Gas detectors and alarms except in open areas where adequate ventilation is provided by natural means. You must test and recalibrate gas detectors quarterly. No more than 90 days may elapse between tests;

(c) Explosion-proof or pressurized electrical equipment to prevent the ignition of explosive gases. Where you use air for pressuring equipment, you must locate the air intake outside of and as far as practicable from hazardous areas; and

(d) Alarms that activate when the mechanical ventilation system fails.

OTHER DRILLING REQUIREMENTS

§250.460 What are the requirements for conducting a well test?

(a) If you intend to conduct a well test, you must include your projected plans for the test with your APD (form BSEE-0123) or in an Application for Permit to Modify (APM) (form BSEE-0124). Your plans must include at least the following information:

- (1) Estimated flowing and shut-in tubing pressures;
- (2) Estimated flow rates and cumulative volumes;
- (3) Time duration of flow, buildup, and drawdown periods;
- (4) Description and rating of surface and subsurface test equipment;
- (5) Schematic drawing, showing the layout of test equipment;
- (6) Description of safety equipment, including gas detectors and fire-fighting equipment;
- (7) Proposed methods to handle or transport produced fluids; and
- (8) Description of the test procedures.

(b) You must give the District Manager at least 24-hours notice before starting a well test.

§250.461 What are the requirements for directional and inclination surveys?

For this subpart, BSEE classifies a well as vertical if the calculated average of inclination readings does not exceed 3 degrees from the vertical.

(a) *Survey requirements for a vertical well.* (1) You must conduct inclination surveys on each vertical well and record the results. Survey intervals may not exceed 1,000 feet during the normal course of drilling;

(2) You must also conduct a directional survey that provides both inclination and azimuth, and

digitally record the results in electronic format:

- (i) Within 500 feet of setting surface or intermediate casing;
- (ii) Within 500 feet of setting any liner; and
- (iii) When you reach total depth.

(b) *Survey requirements for directional well.* You must conduct directional surveys on each directional well and digitally record the results. Surveys must give both inclination and azimuth at intervals not to exceed 500 feet during the normal course of drilling. Intervals during angle-changing portions of the hole may not exceed 100 feet.

(c) *Measurement while drilling.* You may use measurement-while-drilling technology if it meets the requirements of this section.

(d) *Composite survey requirements.* (1) Your composite directional survey must show the interval from the bottom of the conductor casing to total depth. In the absence of conductor casing, the survey must show the interval from the bottom of the drive or structural casing to total depth; and

(2) You must correct all surveys to Universal-Transverse-Mercator-Grid-north or Lambert-Grid-north after making the magnetic-to-true-north correction. Surveys must show the magnetic and grid corrections used and include a listing of the directionally computed inclinations and azimuths.

(e) If you drill within 500 feet of an adjacent lease, the Regional Supervisor may require you to furnish a copy of the well's directional survey to the affected leaseholder. This could occur when the adjoining leaseholder requests a copy of the survey for the protection of correlative rights.

§250.462 What are the source control, containment, and collocated equipment requirements?

For drilling operations using a subsea BOP or surface BOP on a floating facility, you must have the ability to control or contain a blowout event at the sea floor.

(a) To determine your required source control and containment capabilities you must do the following:

(1) Consider a scenario of the wellbore fully evacuated to reservoir fluids, with no restrictions in the well.

(2) Evaluate the performance of the well as designed to determine if a full shut-in can be achieved without having reservoir fluids broach to the sea floor. If your evaluation indicates that the well can only be partially shut-in, then you must determine your ability to flow and capture the residual fluids to a surface production and storage system.

(b) You must have access to and the ability to deploy Source Control and Containment Equipment (SCCE) and all other necessary supporting and collocated equipment to regain control of the well. SCCE means the capping stack, cap-and-flow system, containment dome, and/or other subsea and surface devices, equipment, and vessels, which have the collective purpose to control a spill source and stop the flow of fluids into the environment or to contain fluids escaping into the environment. This SCCE, supporting equipment, and collocated equipment must include, but is not limited to, the following:

- (1) Subsea containment and capture equipment, including containment domes and capping stacks;
- (2) Subsea utility equipment including hydraulic power sources and hydrate control equipment;
- (3) Collocated equipment including dispersant injection equipment;

- (4) Riser systems;
- (5) Remotely operated vehicles (ROVs);
- (6) Capture vessels;
- (7) Support vessels; and
- (8) Storage facilities.

(c) You must submit a description of your source control and containment capabilities to the Regional Supervisor and receive approval before BSEE will approve your APD, Form BSEE-0123. The description of your containment capabilities must contain the following:

- (1) Your source control and containment capabilities for controlling and containing a blowout event at the seafloor;
- (2) A discussion of the determination required in paragraph (a) of this section; and
- (3) Information showing that you have access to and the ability to deploy all equipment required by paragraph (b) of this section.

(d) You must contact the District Manager and Regional Supervisor for reevaluation of your source control and containment capabilities if your:

- (1) Well design changes; or
- (2) Approved source control and containment equipment is out of service.

(e) You must maintain, test, and inspect the source control, containment, and collocated equipment identified in the following table according to these requirements:

Equipment	Requirements, you must:	Additional information
(1) Capping stacks,	(i) Function test all pressure containing critical components on a quarterly frequency (not to exceed 104 days between tests),	Pressure containing critical components are those components that will experience wellbore pressure during a shut-in after being functioned.
	(ii) Pressure test pressure containing critical components on a bi-annual basis, but not later than 210 days from the last pressure test. All pressure testing must be witnessed by BSEE (if available) and a BSEE-approved verification organization	Pressure containing critical components are those components that will experience wellbore pressure during a shut-in. These components include, but are not limited to: All blind rams, wellhead connectors, and outlet valves.
	(iii) Notify BSEE at least 21 days prior to commencing any pressure testing	
(2) Production safety systems used for flow and capture operations,	(i) Meet or exceed the requirements set forth in §§250.800 through 250.808, excluding required equipment that would be installed below the wellhead or that is not applicable to the cap and flow system.	
	(ii) Have all equipment unique to containment operations available for inspection at all times	

(3) Subsea utility equipment,	Have all referenced containment equipment available for inspection at all times	Subsea utility equipment includes, but is not limited to: Hydraulic power sources, debris removal, and hydrate control equipment.
(4) Collocated equipment,	Have equipment available for inspection at all times	Collocated equipment includes, but is not limited to, dispersant injection equipment and other subsea control equipment.

[81 FR 26020, Apr. 29, 2016]

§250.463 Who establishes field drilling rules?

(a) The District Manager may establish field drilling rules different from the requirements of this subpart when geological and engineering information shows that specific operating requirements are appropriate. You must comply with field drilling rules and nonconflicting requirements of this subpart. The District Manager may amend or cancel field drilling rules at any time.

(b) You may request the District Manager to establish, amend, or cancel field drilling rules.

APPLYING FOR A PERMIT TO MODIFY AND WELL RECORDS

§250.465 When must I submit an Application for Permit to Modify (APM) or an End of Operations Report to BSEE?

(a) You must submit an APM (form BSEE-0124) or an End of Operations Report (form BSEE-0125) and other materials to the Regional Supervisor as shown in the following table. You must also submit a public information copy of each form.

When you . . .	Then you must . . .	And . . .
(1) Intend to revise your drilling plan, change major drilling equipment, or plugback,	Submit form BSEE-0124 or request oral approval,	Receive written or oral approval from the District Manager before you begin the intended operation. If you get an approval, you must submit form BSEE-0124 no later than the end of the 3rd business day following the oral approval. In all cases, or you must meet the additional requirements in paragraph (b) of this section.
(2) Determine a well's final surface location, water depth, and the rotary kelly bushing elevation,	Immediately Submit a form BSEE-0124,	Submit a plat certified by a registered land surveyor that meets the requirements of §250.412.
(3) Move a drilling unit from a wellbore before completing a well,	Submit forms BSEE-0124 and BSEE-0125 within 30 days after the suspension of wellbore operations,	Submit appropriate copies of the well records.

(b) If you intend to perform any of the actions specified in paragraph (a)(1) of this section, you must meet the following additional requirements:

(1) Your APM (Form BSEE-0124) must contain a detailed statement of the proposed work that would materially change from the approved APD. The submission of your APM must be accompanied by payment of the service fee listed in §250.125;

(2) Your form BSEE-0124 must include the present status of the well, depth of all casing strings set to date, well depth, present production zones and productive capability, and all other information specified; and

(3) Within 30 days after completing this work, you must submit an End of Operations Report (EOR), Form BSEE-0125, as required under §250.744.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26021, Apr. 29, 2016]

§§250.466--250.469 [Reserved]

ADDITIONAL ARCTIC OCS REQUIREMENTS

SOURCE: 81 FR 46561, July 15, 2016, unless otherwise noted.

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

In addition to complying with all other applicable requirements included in this part, you must provide with your APD all of the following information pertaining to your proposed Arctic OCS exploratory drilling:

(a) A detailed description of:

(1) The environmental, meteorological, and oceanic conditions you expect to encounter at the well site(s);

(2) How you will prepare your equipment, materials, and drilling unit for service in the conditions identified in paragraph (a)(1) of this section, and how your drilling unit will be in compliance with the requirements of §250.713.

(b) A detailed description of all operations necessary in Arctic OCS conditions to transition the rig from being under way to conducting drilling operations and from ending drilling operations to being under way, as well as any anticipated repair and maintenance plans for the drilling unit and equipment. You should include, among other things, a description of how you plan to:

(1) Recover the subsea equipment, including the marine riser and the lower marine riser package;

(2) Recover the BOP;

(3) Recover the auxiliary sub-sea controls and template;

(4) Lay down the drill pipe and secure the drill pipe and marine riser;

(5) Secure the drilling equipment;

(6) Transfer the fluids for transport or disposal;

(7) Secure ancillary equipment like the draw works and lines;

(8) Refuel or transfer fuel;

(9) Offload waste;

(10) Recover the Remotely Operated Vehicles;

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

(12) Offload the drilling crew.

(c) A description of well-specific drilling objectives, timelines, and updated contingency plans for temporary abandonment of the well, including but not limited to the following:

(1) When you will spud the particular well (*i.e.*, begin drilling operations at the well site) identified in the APD;

(2) How long you will take to drill the well;

(3) Anticipated depths and geologic targets, with timelines;

(4) When you expect to set and cement each string of casing;

(5) When and how you would log the well;

(6) Your plans to test the well;

(7) When and how you intend to abandon the well, including specifically addressing your plans for how to move the rig off location and how you will meet the requirements of §250.720(c);

(8) A description of what equipment and vessels will be involved in the process of temporarily abandoning the well due to ice; and

(9) An explanation of how you will integrate these elements into your overall program.

(d) A detailed description of your weather and ice forecasting capability for all phases of the drilling operation, including:

(1) How you will ensure your continuous awareness of potential weather and ice hazards at, and during transition between, wells;

(2) Your plans for managing ice hazards and responding to weather events; and

(3) Verification that you have the capabilities described in your BOEM-approved EP.

(e) A detailed description of how you will comply with the requirements of §250.472.

(f) A statement that you own, or have a contract with a provider for, source control and containment equipment (SCCE), which is capable of controlling and/or containing a worst case discharge, as described in your BOEM-approved EP, when proposing to use a MODU to conduct exploratory drilling operations on the Arctic OCS. The following information must be included in your SCCE submittal:

(1) A detailed description of your or your contractor's SCCE capability to stop or contain flow from an out-of-control well, including your operating assumptions and limitations; your access to and ability to deploy, in accordance with §250.471, all necessary SCCE; and your ability to evaluate the performance of the well design to determine how you can achieve a full shut-in without having reservoir fluids discharged into the environment;

(2) An inventory of the local and regional SCCE, supplies, and services that you own or for which you have a contract with a provider. You must identify each supplier of such equipment and services and provide their locations and telephone numbers;

(3) Where applicable, proof of contracts or membership agreements with cooperatives, service

providers, or other contractors who will provide you with the necessary SCCE or related supplies and services if you do not possess them. The contract or membership agreement must include provisions for ensuring the availability of the personnel and/or equipment on a 24-hour per day basis while you are drilling below or working below the surface casing;

(4) A detailed description of the procedures you plan to use to inspect, test, and maintain your SCCE; and

(5) A detailed description of your plan to ensure that all members of your operating team, who are responsible for operating the SCCE, have received the necessary training to deploy and operate such equipment in Arctic OCS conditions and demonstrate ongoing proficiency in source control operations. You must also identify and include the dates of prior and planned training.

(g) Where it does not conflict with other requirements of this subpart, and except as provided in paragraphs (g)(1) through (11) of this section, you must comply with the requirements of API RP 2N, Third Edition "Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions" (incorporated by reference as specified in §250.198), and provide a detailed description of how you will utilize the best practices included in API RP 2N during your exploratory drilling operations. You are not required to incorporate the following sections of API RP 2N into your drilling operations:

- (1) Sections 6.6.3 through 6.6.4;
- (2) The foundation recommendations in Section 8.4;
- (3) Section 9.6;
- (4) The recommendations for permanently moored systems in Section 9.7;
- (5) The recommendations for pile foundations in Section 9.10;
- (6) Section 12;
- (7) Section 13.2.1;
- (8) Sections 13.8.1.1, 13.8.2.1, 13.8.2.2, 13.8.2.4 through 13.8.2.7;
- (9) Sections 13.9.1, 13.9.2, 13.9.4 through 13.9.8;
- (10) Sections 14 through 16; and
- (11) Section 18.

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

You must meet the following requirements for all exploration wells drilled on the Arctic OCS:

(a) If you use a MODU when drilling below or working below the surface casing, you must have access to the following SCCE capable of stopping or capturing the flow of an out-of-control well:

(1) A capping stack, positioned to ensure that it will arrive at the well location within 24 hours after a loss of well control and can be deployed as directed by the Regional Supervisor pursuant to paragraph (h) of this section;

(2) A cap and flow system, positioned to ensure that it will arrive at the well location within 7 days after a loss of well control and can be deployed as directed by the Regional Supervisor pursuant to paragraph (h) of this section. The cap and flow system must be designed to capture at least the amount

of hydrocarbons equivalent to the calculated worst case discharge rate referenced in your BOEM-approved EP; and

(3) A containment dome, positioned to ensure that it will arrive at the well location within 7 days after a loss of well control and can be deployed as directed by the Regional Supervisor pursuant to paragraph (h) of this section. The containment dome must have the capacity to pump fluids without relying on buoyancy.

(b) You must conduct a monthly stump test of dry-stored capping stacks. If you use a pre-positioned capping stack, you must conduct a stump test prior to each installation on each well.

(c) As required by §250.465(a), if you propose to change your well design, you must submit an APM. For Arctic OCS operations, your APM must include a reevaluation of your SCCE capabilities for any new Worst Case Discharge (WCD) rate, and a demonstration that your SCCE capabilities will meet the criteria in §250.470(f) under the changed well design.

(d) You must conduct tests or exercises of your SCCE, including deployment of your SCCE, when directed by the Regional Supervisor.

(e) You must maintain records pertaining to testing, inspection, and maintenance of your SCCE for at least 10 years and make the records available to any authorized BSEE representative upon request.

(f) You must maintain records pertaining to the use of your SCCE during testing, training, and deployment activities for at least 3 years and make the records available to any authorized BSEE representative upon request.

(g) Upon a loss of well control, you must initiate transit of all SCCE identified in paragraph (a) of this section to the well.

(h) You must deploy and use SCCE when directed by the Regional Supervisor.

(i) Operators may request approval of alternate procedures or equipment to the SCCE requirements of subparagraph (a) of this section in accordance with §250.141. The operator must show and document that the alternate procedures or equipment will provide a level of safety and environmental protection that will meet or exceed the level of safety and environmental protection required by BSEE regulations, including demonstrating that the alternate procedures or equipment will be capable of stopping or capturing the flow of an out-of-control well.

§250.472 What are the relief rig requirements for the Arctic OCS?

(a) In the event of a loss of well control, the Regional Supervisor may direct you to drill a relief well using the relief rig able to kill and permanently plug an out-of-control well as described in your APD. Your relief rig must comply with all other requirements of this part pertaining to drill rig characteristics and capabilities, and it must be able to drill a relief well under anticipated Arctic OCS conditions.

(b) When you are drilling below or working below the surface casing during Arctic OCS exploratory drilling operations, you must have access to a relief rig, different from your primary drilling rig, staged in a location such that it can arrive on site, drill a relief well, kill and abandon the original well, and abandon the relief well prior to expected seasonal ice encroachment at the drill site, but no later than 45 days after the loss of well control.

(c) Operators may request approval of alternative compliance measures to the relief rig requirement in accordance with §250.141. The operator must show and document that the alternate compliance measure will meet or exceed the level of safety and environmental protection required by BSEE regulations, including demonstrating that the alternate compliance measure will be able to kill and permanently plug an out-of-control well.

§250.473 What must I do to protect health, safety, property, and the environment while operating on the Arctic OCS?

In addition to the requirements set forth in §250.107, when conducting exploratory drilling operations on the Arctic OCS, you must protect health, safety, property, and the environment by using the following:

- (a) Equipment and materials that are rated or de-rated for service under conditions that can be reasonably expected during your operations; and
- (b) Measures to address human factors associated with weather conditions that can be reasonably expected during your operations including, but not limited to, provision of proper attire and equipment, construction of protected work spaces, and management of shifts.

HYDROGEN SULFIDE

§250.490 Hydrogen sulfide.

(a) *What precautions must I take when operating in an H₂S area?* You must:

(1) Take all necessary and feasible precautions and measures to protect personnel from the toxic effects of H₂S and to mitigate damage to property and the environment caused by H₂S. You must follow the requirements of this section when conducting drilling, well-completion/well-workover, and production operations in zones with H₂S present and when conducting operations in zones where the presence of H₂S is unknown. You do not need to follow these requirements when operating in zones where the absence of H₂S has been confirmed; and

(2) Follow your approved contingency plan.

(b) *Definitions.* Terms used in this section have the following meanings:

Facility means a vessel, a structure, or an artificial island used for drilling, well-completion, well-workover, and/or production operations.

H₂S absent means:

(1) Drilling, logging, coring, testing, or producing operations have confirmed the absence of H₂S in concentrations that could potentially result in atmospheric concentrations of 20 ppm or more of H₂S; or

(2) Drilling in the surrounding areas and correlation of geological and seismic data with equivalent stratigraphic units have confirmed an absence of H₂S throughout the area to be drilled.

H₂S present means that drilling, logging, coring, testing, or producing operations have confirmed the presence of H₂S in concentrations and volumes that could potentially result in atmospheric concentrations of 20 ppm or more of H₂S.

H₂S unknown means the designation of a zone or geologic formation where neither the presence nor absence of H₂S has been confirmed.

Well-control fluid means drilling mud and completion or workover fluid as appropriate to the particular operation being conducted.

(c) *Classifying an area for the presence of H₂S.* You must:

(1) Request and obtain an approved classification for the area from the Regional Supervisor before you begin operations. Classifications are "H₂S absent," "H₂S present," or "H₂S unknown";

(2) Submit your request with your application for permit to drill;

(3) Support your request with available information such as geologic and geophysical data and correlations, well logs, formation tests, cores and analysis of formation fluids; and

(4) Submit a request for reclassification of a zone when additional data indicate a different classification is needed.

(d) *What do I do if conditions change?* If you encounter H₂S that could potentially result in atmospheric concentrations of 20 ppm or more in areas not previously classified as having H₂S present, you must immediately notify BSEE and begin to follow requirements for areas with H₂S present.

(e) *What are the requirements for conducting simultaneous operations?* When conducting any combination of drilling, well-completion, well-workover, and production operations simultaneously, you must follow the requirements in the section applicable to each individual operation.

(f) *Requirements for submitting an H₂S Contingency Plan.* Before you begin operations, you must submit an H₂S Contingency Plan to the District Manager for approval. Do not begin operations before the District Manager approves your plan. You must keep a copy of the approved plan in the field, and you must follow the plan at all times. Your plan must include:

(1) Safety procedures and rules that you will follow concerning equipment, drills, and smoking;

(2) Training you provide for employees, contractors, and visitors;

(3) Job position and title of the person responsible for the overall safety of personnel;

(4) Other key positions, how these positions fit into your organization, and what the functions, duties, and responsibilities of those job positions are;

(5) Actions that you will take when the concentration of H₂S in the atmosphere reaches 20 ppm, who will be responsible for those actions, and a description of the audible and visual alarms to be activated;

(6) Briefing areas where personnel will assemble during an H₂S alert. You must have at least two briefing areas on each facility and use the briefing area that is upwind of the H₂S source at any given time;

(7) Criteria you will use to decide when to evacuate the facility and procedures you will use to safely evacuate all personnel from the facility by vessel, capsule, or lifeboat. If you use helicopters during H₂S alerts, describe the types of H₂S emergencies during which you consider the risk of helicopter activity to be acceptable and the precautions you will take during the flights;

(8) Procedures you will use to safely position all vessels attendant to the facility. Indicate where you will locate the vessels with respect to wind direction. Include the distance from the facility and what procedures you will use to safely relocate the vessels in an emergency;

(9) How you will provide protective-breathing equipment for all personnel, including contractors and visitors;

(10) The agencies and facilities you will notify in case of a release of H₂S (that constitutes an emergency), how you will notify them, and their telephone numbers. Include all facilities that might be exposed to atmospheric concentrations of 20 ppm or more of H₂S;

(11) The medical personnel and facilities you will use if needed, their addresses, and telephone numbers;

(12) H₂S detector locations in production facilities producing gas containing 20 ppm or more of H₂S. Include an "H₂S Detector Location Drawing" showing:

- (i) All vessels, flare outlets, wellheads, and other equipment handling production containing H₂S;
- (ii) Approximate maximum concentration of H₂S in the gas stream; and
- (iii) Location of all H₂S sensors included in your contingency plan;

(13) Operational conditions when you expect to flare gas containing H₂S including the estimated maximum gas flow rate, H₂S concentration, and duration of flaring;

(14) Your assessment of the risks to personnel during flaring and what precautionary measures you will take;

(15) Primary and alternate methods to ignite the flare and procedures for sustaining ignition and monitoring the status of the flare (*i.e.*, ignited or extinguished);

(16) Procedures to shut off the gas to the flare in the event the flare is extinguished;

(17) Portable or fixed sulphur dioxide (SO₂)-detection system(s) you will use to determine SO₂ concentration and exposure hazard when H₂S is burned;

(18) Increased monitoring and warning procedures you will take when the SO₂ concentration in the atmosphere reaches 2 ppm;

(19) Personnel protection measures or evacuation procedures you will initiate when the SO₂ concentration in the atmosphere reaches 5 ppm;

(20) Engineering controls to protect personnel from SO₂; and

(21) Any special equipment, procedures, or precautions you will use if you conduct any combination of drilling, well-completion, well-workover, and production operations simultaneously.

(g) *Training program:* (1) *When and how often do employees need to be trained?* All operators and contract personnel must complete an H₂S training program to meet the requirements of this section:

- (i) Before beginning work at the facility; and
- (ii) Each year, within 1 year after completion of the previous class.

(2) *What training documentation do I need?* For each individual working on the platform, either:

- (i) You must have documentation of this training at the facility where the individual is employed; or
- (ii) The employee must carry a training completion card.

(3) *What training do I need to give to visitors and employees previously trained on another facility?*

(i) Trained employees or contractors transferred from another facility must attend a supplemental briefing on your H₂S equipment and procedures before beginning duty at your facility;

(ii) Visitors who will remain on your facility more than 24 hours must receive the training required for employees by paragraph (g)(4) of this section; and

(iii) Visitors who will depart before spending 24 hours on the facility are exempt from the training

required for employees, but they must, upon arrival, complete a briefing that includes:

(A) Information on the location and use of an assigned respirator; practice in donning and adjusting the assigned respirator; information on the safe briefing areas, alarm system, and hazards of H₂S and SO₂; and

(B) Instructions on their responsibilities in the event of an H₂S release.

(4) *What training must I provide to all other employees?* You must train all individuals on your facility on the:

(i) Hazards of H₂S and of SO₂ and the provisions for personnel safety contained in the H₂S Contingency Plan;

(ii) Proper use of safety equipment which the employee may be required to use;

(iii) Location of protective breathing equipment, H₂S detectors and alarms, ventilation equipment, briefing areas, warning systems, evacuation procedures, and the direction of prevailing winds;

(iv) Restrictions and corrective measures concerning beards, spectacles, and contact lenses in conformance with ANSI Z88.2, American National Standard for Respiratory Protection (as specified in §250.198);

(v) Basic first-aid procedures applicable to victims of H₂S exposure. During all drills and training sessions, you must address procedures for rescue and first aid for H₂S victims;

(vi) Location of:

(A) The first-aid kit on the facility;

(B) Resuscitators; and

(C) Litter or other device on the facility.

(vii) Meaning of all warning signals.

(5) *Do I need to post safety information?* You must prominently post safety information on the facility and on vessels serving the facility (*i.e.*, basic first-aid, escape routes, instructions for use of life boats, *etc.*).

(h) *Drills. (1) When and how often do I need to conduct drills on H₂S safety discussions on the facility?* You must:

(i) Conduct a drill for each person at the facility during normal duty hours at least once every 7-day period. The drills must consist of a dry-run performance of personnel activities related to assigned jobs.

(ii) At a safety meeting or other meetings of all personnel, discuss drill performance, new H₂S considerations at the facility, and other updated H₂S information at least monthly.

(2) *What documentation do I need?* You must keep records of attendance for:

(i) Drilling, well-completion, and well-workover operations at the facility until operations are completed; and

(ii) Production operations at the facility or at the nearest field office for 1 year.

(i) *Visual and audible warning systems: (1) How must I install wind direction equipment?* You must install wind-direction equipment in a location visible at all times to individuals on or in the immediate vicinity of the facility.

(2) *When do I need to display operational danger signs, display flags, or activate visual or audible alarms?*

(i) You must display warning signs at all times on facilities with wells capable of producing H₂S and on facilities that process gas containing H₂S in concentrations of 20 ppm or more.

(ii) In addition to the signs, you must activate audible alarms and display flags or activate flashing red lights when atmospheric concentration of H₂S reaches 20 ppm.

(3) *What are the requirements for signs?* Each sign must be a high-visibility yellow color with black lettering as follows:

Letter height	Wording
12 inches	Danger.
	Poisonous Gas.
	Hydrogen Sulfide.
7 inches	Do not approach if red flag is flying.
(Use appropriate wording at right)	Do not approach if red lights are flashing.

(4) *May I use existing signs?* You may use existing signs containing the words "Danger-Hydrogen Sulfide-H₂S," provided the words "Poisonous Gas. Do Not Approach if Red Flag is Flying" or "Red Lights are Flashing" in lettering of a minimum of 7 inches in height are displayed on a sign immediately adjacent to the existing sign.

(5) *What are the requirements for flashing lights or flags?* You must activate a sufficient number of lights or hoist a sufficient number of flags to be visible to vessels and aircraft. Each light must be of sufficient intensity to be seen by approaching vessels or aircraft any time it is activated (day or night). Each flag must be red, rectangular, a minimum width of 3 feet, and a minimum height of 2 feet.

(6) *What is an audible warning system?* An audible warning system is a public address system or siren, horn, or other similar warning device with a unique sound used only for H₂S.

(7) *Are there any other requirements for visual or audible warning devices?* Yes, you must:

(i) Illuminate all signs and flags at night and under conditions of poor visibility; and

(ii) Use warning devices that are suitable for the electrical classification of the area.

(8) *What actions must I take when the alarms are activated?* When the warning devices are activated, the designated responsible persons must inform personnel of the level of danger and issue instructions on the initiation of appropriate protective measures.

(j) *H₂S-detection and H₂S monitoring equipment: (1) What are the requirements for an H₂S detection system?* An H₂S detection system must:

(i) Be capable of sensing a minimum of 10 ppm of H₂S in the atmosphere; and

(ii) Activate audible and visual alarms when the concentration of H₂S in the atmosphere reaches 20 ppm.

(2) *Where must I have sensors for drilling, well-completion, and well-workover operations?* You must locate sensors at the:

- (i) Bell nipple;
- (ii) Mud-return line receiver tank (possum belly);
- (iii) Pipe-trip tank;
- (iv) Shale shaker;
- (v) Well-control fluid pit area;
- (vi) Driller's station;
- (vii) Living quarters; and
- (viii) All other areas where H₂S may accumulate.

(3) *Do I need mud sensors?* The District Manager may require mud sensors in the possum belly in cases where the ambient air sensors in the mud-return system do not consistently detect the presence of H₂S.

(4) *How often must I observe the sensors?* During drilling, well-completion and well-workover operations, you must continuously observe the H₂S levels indicated by the monitors in the work areas during the following operations:

- (i) When you pull a wet string of drill pipe or workover string;
- (ii) When circulating bottoms-up after a drilling break;
- (iii) During cementing operations;
- (iv) During logging operations; and
- (v) When circulating to condition mud or other well-control fluid.

(5) *Where must I have sensors for production operations?* On a platform where gas containing H₂S of 20 ppm or greater is produced, processed, or otherwise handled:

(i) You must have a sensor in rooms, buildings, deck areas, or low-laying deck areas not otherwise covered by paragraph (j)(2) of this section, where atmospheric concentrations of H₂S could reach 20 ppm or more. You must have at least one sensor per 400 square feet of deck area or fractional part of 400 square feet;

(ii) You must have a sensor in buildings where personnel have their living quarters;

(iii) You must have a sensor within 10 feet of each vessel, compressor, wellhead, manifold, or pump, which could release enough H₂S to result in atmospheric concentrations of 20 ppm at a distance of 10 feet from the component;

(iv) You may use one sensor to detect H₂S around multiple pieces of equipment, provided the sensor is located no more than 10 feet from each piece, except that you need to use at least two sensors to monitor compressors exceeding 50 horsepower;

(v) You do not need to have sensors near wells that are shut in at the master valve and sealed

closed;

(vi) When you determine where to place sensors, you must consider:

(A) The location of system fittings, flanges, valves, and other devices subject to leaks to the atmosphere; and

(B) Design factors, such as the type of decking and the location of fire walls; and

(vii) The District Manager may require additional sensors or other monitoring capabilities, if warranted by site specific conditions.

(6) *How must I functionally test the H₂S Detectors?* (i) Personnel trained to calibrate the particular H₂S detector equipment being used must test detectors by exposing them to a known concentration in the range of 10 to 30 ppm of H₂S.

(ii) If the results of any functional test are not within 2 ppm or 10 percent, whichever is greater, of the applied concentration, recalibrate the instrument.

(7) *How often must I test my detectors?* (i) When conducting drilling, drill stem testing, well-completion, or well-workover operations in areas classified as H₂S present or H₂S unknown, test all detectors at least once every 24 hours. When drilling, begin functional testing before the bit is 1,500 feet (vertically) above the potential H₂S zone.

(ii) When conducting production operations, test all detectors at least every 14 days between tests.

(iii) If equipment requires calibration as a result of two consecutive functional tests, the District Manager may require that H₂S-detection and H₂S-monitoring equipment be functionally tested and calibrated more frequently.

(8) *What documentation must I keep?* (i) You must maintain records of testing and calibrations (in the drilling or production operations report, as applicable) at the facility to show the present status and history of each device, including dates and details concerning:

(A) Installation;

(B) Removal;

(C) Inspection;

(D) Repairs;

(E) Adjustments; and

(F) Reinstallation.

(ii) Records must be available for inspection by BSEE personnel.

(9) *What are the requirements for nearby vessels?* If vessels are stationed overnight alongside facilities in areas of H₂S present or H₂S unknown, you must equip vessels with an H₂S-detection system that activates audible and visual alarms when the concentration of H₂S in the atmosphere reaches 20 ppm. This requirement does not apply to vessels positioned upwind and at a safe distance from the facility in accordance with the positioning procedure described in the approved H₂S Contingency Plan.

(10) *What are the requirements for nearby facilities?* The District Manager may require you to equip nearby facilities with portable or fixed H₂S detector(s) and to test and calibrate those detectors. To invoke

this requirement, the District Manager will consider dispersion modeling results from a possible release to determine if 20 ppm H₂S concentration levels could be exceeded at nearby facilities.

(11) *What must I do to protect against SO₂ if I burn gas containing H₂S?* You must:

(i) Monitor the SO₂ concentration in the air with portable or strategically placed fixed devices capable of detecting a minimum of 2 ppm of SO₂;

(ii) Take readings at least hourly and at any time personnel detect SO₂ odor or nasal irritation;

(iii) Implement the personnel protective measures specified in the H₂S Contingency Plan if the SO₂ concentration in the work area reaches 2 ppm; and

(iv) Calibrate devices every 3 months if you use fixed or portable electronic sensing devices to detect SO₂.

(12) *May I use alternative measures?* You may follow alternative measures instead of those in paragraph (j)(11) of this section if you propose and the Regional Supervisor approves the alternative measures.

(13) *What are the requirements for protective-breathing equipment?* In an area classified as H₂S present or H₂S unknown, you must:

(i) Provide all personnel, including contractors and visitors on a facility, with immediate access to self-contained pressure-demand-type respirators with hoseline capability and breathing time of at least 15 minutes.

(ii) Design, select, use, and maintain respirators in conformance with ANSI Z88.2 (as specified in §250.198).

(iii) Make available at least two voice-transmission devices, which can be used while wearing a respirator, for use by designated personnel.

(iv) Make spectacle kits available as needed.

(v) Store protective-breathing equipment in a location that is quickly and easily accessible to all personnel.

(vi) Label all breathing-air bottles as containing breathing-quality air for human use.

(vii) Ensure that vessels attendant to facilities carry appropriate protective-breathing equipment for each crew member. The District Manager may require additional protective-breathing equipment on certain vessels attendant to the facility.

(viii) During H₂S alerts, limit helicopter flights to and from facilities to the conditions specified in the H₂S Contingency Plan. During authorized flights, the flight crew and passengers must use pressure-demand-type respirators. You must train all members of flight crews in the use of the particular type(s) of respirator equipment made available.

(ix) As appropriate to the particular operation(s), (production, drilling, well-completion or well-workover operations, or any combination of them), provide a system of breathing-air manifolds, hoses, and masks at the facility and the briefing areas. You must provide a cascade air-bottle system for the breathing-air manifolds to refill individual protective-breathing apparatus bottles. The cascade air-bottle system may be recharged by a high-pressure compressor suitable for providing breathing-quality air, provided the compressor suction is located in an uncontaminated atmosphere.

(k) *Personnel safety equipment:* (1) What additional personnel-safety equipment do I need? You

must ensure that your facility has:

(i) Portable H₂S detectors capable of detecting a 10 ppm concentration of H₂S in the air available for use by all personnel;

(ii) Retrieval ropes with safety harnesses to retrieve incapacitated personnel from contaminated areas;

(iii) Chalkboards and/or note pads for communication purposes located on the rig floor, shale-shaker area, the cement-pump rooms, well-bay areas, production processing equipment area, gas compressor area, and pipeline-pump area;

(iv) Bull horns and flashing lights; and

(v) At least three resuscitators on manned facilities, and a number equal to the personnel on board, not to exceed three, on normally unmanned facilities, complete with face masks, oxygen bottles, and spare oxygen bottles.

(2) *What are the requirements for ventilation equipment? You must:*

(i) Use only explosion-proof ventilation devices;

(ii) Install ventilation devices in areas where H₂S or SO₂ may accumulate; and

(iii) Provide movable ventilation devices in work areas. The movable ventilation devices must be multidirectional and capable of dispersing H₂S or SO₂ vapors away from working personnel.

(3) *What other personnel safety equipment do I need? You must have the following equipment readily available on each facility:*

(i) A first-aid kit of appropriate size and content for the number of personnel on the facility; and

(ii) At least one litter or an equivalent device.

(l) *Do I need to notify BSEE in the event of an H₂S release? You must notify BSEE without delay in the event of a gas release which results in a 15-minute time-weighted average atmospheric concentration of H₂S of 20 ppm or more anywhere on the OCS facility. You must report these gas releases to the District Manager immediately by oral communication, with a written follow-up report within 15 days, pursuant to §§250.188 through 250.190.*

(m) *Do I need to use special drilling, completion and workover fluids or procedures? When working in an area classified as H₂S present or H₂S unknown:*

(1) You may use either water- or oil-base muds in accordance with §250.300(b)(1).

(2) If you use water-base well-control fluids, and if ambient air sensors detect H₂S, you must immediately conduct either the Garrett-Gas-Train test or a comparable test for soluble sulfides to confirm the presence of H₂S.

(3) If the concentration detected by air sensors is over 20 ppm, personnel conducting the tests must don protective-breathing equipment conforming to paragraph (j)(13) of this section.

(4) You must maintain on the facility sufficient quantities of additives for the control of H₂S, well-control fluid pH, and corrosion equipment.

(i) *Scavengers.* You must have scavengers for control of H₂S available on the facility. When H₂S is

detected, you must add scavengers as needed. You must suspend drilling until the scavenger is circulated throughout the system.

(ii) *Control pH.* You must add additives for the control of pH to water-base well-control fluids in sufficient quantities to maintain pH of at least 10.0.

(iii) *Corrosion inhibitors.* You must add additives to the well-control fluid system as needed for the control of corrosion.

(5) You must degas well-control fluids containing H₂S at the optimum location for the particular facility. You must collect the gases removed and burn them in a closed flare system conforming to paragraph (q)(6) of this section.

(n) *What must I do in the event of a kick?* In the event of a kick, you must use one of the following alternatives to dispose of the well-influx fluids giving consideration to personnel safety, possible environmental damage, and possible facility well-equipment damage:

(1) Contain the well-fluid influx by shutting in the well and pumping the fluids back into the formation.

(2) Control the kick by using appropriate well-control techniques to prevent formation fracturing in an open hole within the pressure limits of the well equipment (drill pipe, work string, casing, wellhead, BOP system, and related equipment). The disposal of H₂S and other gases must be through pressurized or atmospheric mud-separator equipment depending on volume, pressure and concentration of H₂S. The equipment must be designed to recover well-control fluids and burn the gases separated from the well-control fluid. The well-control fluid must be treated to neutralize H₂S and restore and maintain the proper quality.

(o) *Well testing in a zone known to contain H₂S.* When testing a well in a zone with H₂S present, you must do all of the following:

(1) Before starting a well test, conduct safety meetings for all personnel who will be on the facility during the test. At the meetings, emphasize the use of protective-breathing equipment, first-aid procedures, and the Contingency Plan. Only competent personnel who are trained and are knowledgeable of the hazardous effects of H₂S must be engaged in these tests.

(2) Perform well testing with the minimum number of personnel in the immediate vicinity of the rig floor and with the appropriate test equipment to safely and adequately perform the test. During the test, you must continuously monitor H₂S levels.

(3) Not burn produced gases except through a flare which meets the requirements of paragraph (q)(6) of this section. Before flaring gas containing H₂S, you must activate SO₂ monitoring equipment in accordance with paragraph (j)(11) of this section. If you detect SO₂ in excess of 2 ppm, you must implement the personnel protective measures in your H₂S Contingency Plan, required by paragraph (f) of this section. You must also follow the requirements of §250.1164. You must pipe gases from stored test fluids into the flare outlet and burn them.

(4) Use downhole test tools and wellhead equipment suitable for H₂S service.

(5) Use tubulars suitable for H₂S service. You must not use drill pipe for well testing without the prior approval of the District Manager. Water cushions must be thoroughly inhibited in order to prevent H₂S attack on metals. You must flush the test string fluid treated for this purpose after completion of the test.

(6) Use surface test units and related equipment that is designed for H₂S service.

(p) *Metallurgical properties of equipment.* When operating in a zone with H₂S present, you must use equipment that is constructed of materials with metallurgical properties that resist or prevent sulfide

stress cracking (also known as hydrogen embrittlement, stress corrosion cracking, or H₂S embrittlement), chloride-stress cracking, hydrogen-induced cracking, and other failure modes. You must do all of the following:

(1) Use tubulars and other equipment, casing, tubing, drill pipe, couplings, flanges, and related equipment that is designed for H₂S service.

(2) Use BOP system components, wellhead, pressure-control equipment, and related equipment exposed to H₂S-bearing fluids in conformance with NACE Standard MR0175-03 (as specified in §250.198).

(3) Use temporary downhole well-security devices such as retrievable packers and bridge plugs that are designed for H₂S service.

(4) When producing in zones bearing H₂S, use equipment constructed of materials capable of resisting or preventing sulfide stress cracking.

(5) Keep the use of welding to a minimum during the installation or modification of a production facility. Welding must be done in a manner that ensures resistance to sulfide stress cracking.

(q) *General requirements when operating in an H₂S zone:* (1) *Coring operations.* When you conduct coring operations in H₂S-bearing zones, all personnel in the working area must wear protective-breathing equipment at least 10 stands in advance of retrieving the core barrel. Cores to be transported must be sealed and marked for the presence of H₂S.

(2) *Logging operations.* You must treat and condition well-control fluid in use for logging operations to minimize the effects of H₂S on the logging equipment.

(3) *Stripping operations.* Personnel must monitor displaced well-control fluid returns and wear protective-breathing equipment in the working area when the atmospheric concentration of H₂S reaches 20 ppm or if the well is under pressure.

(4) *Gas-cut well-control fluid or well kick from H₂S-bearing zone.* If you decide to circulate out a kick, personnel in the working area during bottoms-up and extended-kill operations must wear protective-breathing equipment.

(5) *Drill- and workover-string design and precautions.* Drill- and workover-strings must be designed consistent with the anticipated depth, conditions of the hole, and reservoir environment to be encountered. You must minimize exposure of the drill- or workover-string to high stresses as much as practical and consistent with well conditions. Proper handling techniques must be taken to minimize notching and stress concentrations. Precautions must be taken to minimize stresses caused by doglegs, improper stiffness ratios, improper torque, whip, abrasive wear on tool joints, and joint imbalance.

(6) *Flare system.* The flare outlet must be of a diameter that allows easy nonrestricted flow of gas. You must locate flare line outlets on the downside of the facility and as far from the facility as is feasible, taking into account the prevailing wind directions, the wake effects caused by the facility and adjacent structure(s), and the height of all such facilities and structures. You must equip the flare outlet with an automatic ignition system including a pilot-light gas source or an equivalent system. You must have alternate methods for igniting the flare. You must pipe to the flare system used for H₂S all vents from production process equipment, tanks, relief valves, burst plates, and similar devices.

(7) *Corrosion mitigation.* You must use effective means of monitoring and controlling corrosion caused by acid gases (H₂S and CO₂) in both the downhole and surface portions of a production system. You must take specific corrosion monitoring and mitigating measures in areas of unusually severe corrosion where accumulation of water and/or higher concentration of H₂S exists.

(8) *Wireline lubricators.* Lubricators which may be exposed to fluids containing H₂S must be of H₂S-resistant materials.

(9) *Fuel and/or instrument gas.* You must not use gas containing H₂S for instrument gas. You must not use gas containing H₂S for fuel gas without the prior approval of the District Manager.

(10) *Sensing lines and devices.* Metals used for sensing line and safety-control devices which are necessarily exposed to H₂S-bearing fluids must be constructed of H₂S-corrosion resistant materials or coated so as to resist H₂S corrosion.

(11) *Elastomer seals.* You must use H₂S-resistant materials for all seals which may be exposed to fluids containing H₂S.

(12) *Water disposal.* If you dispose of produced water by means other than subsurface injection, you must submit to the District Manager an analysis of the anticipated H₂S content of the water at the final treatment vessel and at the discharge point. The District Manager may require that the water be treated for removal of H₂S. The District Manager may require the submittal of an updated analysis if the water disposal rate or the potential H₂S content increases.

(13) *Deck drains.* You must equip open deck drains with traps or similar devices to prevent the escape of H₂S gas into the atmosphere.

(14) *Sealed voids.* You must take precautions to eliminate sealed spaces in piping designs (e.g., slip-on flanges, reinforcing pads) which can be invaded by atomic hydrogen when H₂S is present.