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| When | The minimum BOP stack must include |
|---|--|
| (1) The expected pressure is less than 5,000 psi. | Three BOPs consisting of an annular, one set of pipe rams, and one set of blind-shear rams. |
| (2) The expected pressure is 5,000 psi or greater or you use multiple tubing strings. | Four BOPs consisting of an annular, two sets of pipe rams, and one set of blind-shear rams. |
| (3) You handle multiple tubing strings simultaneously. | Four BOPs consisting of an annular, one set of pipe rams, one set of dual pipe rams, and one set of blind-shear rams. |
| (4) You use a tapered drill string, | At least one set of pipe rams that are capable of sealing around each size of drill string. If the expected pressure is greater than 5,000 psi, then you must have at least two sets of pipe rams that are capable of sealing around the larger size drill string. You may substitute one set of variable bore rams for two sets of pipe rams. |

(c) The BOP systems for well completions must be equipped with the following:

(1) A hydraulic-actuating system that provides sufficient accumulator capacity to supply 1.5 times the volume necessary to close all BOP equipment units with a minimum pressure of 200 psi above the precharge pressure without assistance from a charging system. Accumulator regulators supplied by rig air and without a secondary source of pneumatic supply, must be equipped with manual overrides, or alternately, other devices provided to ensure capability of hydraulic operations if rig air is lost.

(2) A secondary power source, independent from the primary power source, with sufficient capacity to close all BOP system components and hold them closed.

(3) Locking devices for the pipe-ram preventers.

(4) At least one remote BOP-control station and one BOP-control station on the rig floor.

(5) A choke line and a kill line each equipped with two full opening valves and a choke manifold. At least one of the valves on the choke line shall be remotely controlled. At least one of the valves on the kill line shall be remotely controlled, except that a check valve on the kill line in lieu of the remotely controlled valve may be installed provided that two readily accessible manual valves are in place and the check valve is placed between the manual valves and the pump. This equipment shall have a pressure rating at least equivalent to the ram preventers.

(d) An inside BOP or a spring-loaded, back-pressure safety valve and an essentially full-opening, work-string

safety valve in the open position shall be maintained on the rig floor at all times during well-completion operations. A wrench to fit the work-string safety valve shall be readily available. Proper connections shall be readily available for inserting valves in the work string.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50616, Dec. 8, 1989; 58 FR 49928, Sept. 24, 1993. Redesignated at 62 29479, May 29, 1998, as amended at 68 FR 8434, Feb. 20, 2003; 74 FR 46908, Sept. 14, 2009]

§ 250.516 Blowout preventer system tests, inspections, and maintenance.

(a) *BOP pressure testing timeframes.* You must pressure test your BOP system:

(1) When installed; and

(2) Before 14 days have elapsed since your last BOP pressure test. You must begin to test your BOP system before 12 a.m. (midnight) on the 14th day following the conclusion of the previous test. However, the District Manager may require testing every 7 days if conditions or BOP performance warrant.

(b) *BOP test pressures.* When you test the BOP system, you must conduct a low pressure and a high pressure test for each BOP component. Each individual pressure test must hold pressure long enough to demonstrate that the tested component(s) holds the required pressure. The District Manager may approve or require other test pressures or practices. Required test pressures are as follows:

(1) All low pressure tests must be between 200 and 300 psi. Any initial pressure above 300 psi must be bled back to a pressure between 200 and 300 psi before starting the test. If the initial pressure exceeds 500 psi, you must bleed back to zero and reinitiate the

test. You must conduct the low pressure test before the high pressure test.

(2) For ram-type BOP's, choke manifold, and other BOP equipment, the high pressure test must equal the rated working pressure of the equipment.

(3) For annular-type BOP's, the high pressure test must equal 70 percent of the rated working pressure of the equipment.

(c) *Duration of pressure test.* Each test must hold the required pressure for 5 minutes.

(1) For surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable if you record your test pressures on the outermost half of a 4-hour chart, on a 1-hour chart, or on a digital recorder.

(2) If the equipment does not hold the required pressure during a test, you must remedy the problem and retest the affected component(s).

(d) *Additional BOP testing requirements.* You must:

(1) Use water to test the surface BOP system;

(2) Stump test a subsurface BOP system before installation. You must use water to stump test a subsea BOP system. You may use drilling or completion fluids to conduct subsequent tests of a subsea BOP system;

(3) Alternate tests between control stations and pods. If a control station or pod is not functional, you must suspend further completion operations until that station or pod is operable;

(4) Pressure test the blind or blind-shear ram at least every 30 days;

(5) Function test annulars and rams every 7 days;

(6) Pressure-test variable bore-pipe rams against all sizes of pipe in use, excluding drill collars and bottom-hole tools; and

(7) Test affected BOP components following the disconnection or repair of any well-pressure containment seal in the wellhead or BOP stack assembly;

(e) *Postponing BOP tests.* You may postpone a BOP test if you have well-control problems. You must conduct the required BOP test as soon as possible (*i.e.*, first trip out of the hole) after the problem has been remedied. You must record the reason for postponing any test in the driller's report.

(f) *Weekly crew drills.* You must conduct a weekly drill to familiarize all personnel engaged in well-completion operations with appropriate safety measures.

(g) *BOP inspections.* You must visually inspect your BOP system and marine riser at least once each day if weather and sea conditions permit. You may use television cameras to inspect this equipment. The District Manager may approve alternate methods and frequencies to inspect a marine riser.

(h) *BOP maintenance.* You must maintain your BOP system to ensure that the equipment functions properly.

(i) *BOP test records.* You must record the time, date, and results of all pressure tests, actuations, crew drills, and inspections of the BOP system, system components, and marine riser in the driller's report. In addition, you must:

(1) Record BOP test pressures on pressure charts;

(2) Have your onsite representative certify (sign and date) BOP test charts and reports as correct;

(3) Document the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. You may reference a BOP test plan if it is available at the facility;

(4) Identify the control station or pod used during the test;

(5) Identify any problems or irregularities observed during BOP system and equipment testing and record actions taken to remedy the problems or irregularities;

(6) Retain all records including pressure charts, driller's report, and referenced documents pertaining to BOP tests, actuations, and inspections at the facility for the duration of the completion activity; and

(7) After completion of the well, you must retain all the records listed in paragraph (i)(6) of this section for a period of 2 years at the facility, at the lessee's field office nearest the OCS facility, or at another location conveniently available to the District Manager.

(j) *Alternate methods.* The District Manager may require, or approve, more frequent testing, as well as different

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test pressures and inspection methods, or other practices.

[63 FR 29607, June 1, 1998]

§ 250.517 Tubing and wellhead equipment.

(a) No tubing string shall be placed in service or continue to be used unless such tubing string has the necessary strength and pressure integrity and is otherwise suitable for its intended use.

(b) In the event of prolonged operations such as milling, fishing, jarring, or washing over that could damage the casing, the casing shall be pressure-tested, calipered, or otherwise evaluated every 30 days and the results submitted to the District Manager.

(c) When the tree is installed, you must equip wells to monitor for casing pressure according to the following chart:

| If you have * * * | you must equip * * * | so you can monitor * * * |
|--|--|---|
| (1) fixed platform wells, (2) subsea wells, (3) hybrid* wells, | the wellhead, the tubing head, the surface wellhead, | all annuli (A, B, C, D, etc., annuli). the production casing annulus (A annulus). all annuli at the surface (A and B riser annuli). If the production casing below the mudline and the production casing riser above the mudline are pressure isolated from each other, provisions must be made to monitor the production casing below the mudline for casing pressure. |

* Characterized as a well drilled with a subsea wellhead and completed with a surface casing head, a surface tubing head, a surface tubing hanger, and a surface christmas tree.

(d) Wellhead, tree, and related equipment shall have a pressure rating greater than the shut-in tubing pressure and shall be designed, installed, used, maintained, and tested so as to achieve and maintain pressure control. New wells completed as flowing or gas-lift wells shall be equipped with a minimum of one master valve and one surface safety valve, installed above the master valve, in the vertical run of the tree.

(e) Subsurface safety equipment shall be installed, maintained, and tested in compliance with § 250.801 of this part.

[53 FR 10690, Apr. 1, 1988, as amended at 55 FR 47753 Nov. 15, 1990. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998; 75 FR 23584, May 4, 2010]

CASING PRESSURE MANAGEMENT

SOURCE: 75 FR 23584, May 4, 2010, unless otherwise noted.

§ 250.518 What are the requirements for casing pressure management?

Once you install your wellhead, you must meet the casing pressure management requirements of API RP 90 (incorporated by reference as specified in § 250.198) and the requirements of §§ 250.519 through 250.530. If there is a conflict between API RP 90 and the casing pressure requirements of this subpart, you must follow the requirements of this subpart.

§ 250.519 How often do I have to monitor for casing pressure?

You must monitor for casing pressure in your well according to the following table:

| If you have * * * | you must monitor * * * | with a minimum one pressure data point recorded per * * * |
|--|---|---|
| (a) fixed platform wells, (b) subsea wells, (c) hybrid wells, (d) wells operating under a casing pressure request on a manned fixed platform, (e) wells operating under a casing pressure request on an unmanned fixed platform, | monthly, continuously, continuously, daily, weekly, | month for each casing. day for the production casing. day for each riser and/or the production casing. day for each casing. week for each casing. |