

(d) Public information copies of Form MMS-125 shall be submitted in accordance with § 250.190.

[53 FR 10690, Apr. 1, 1988, as amended at 58 FR 49928, Sept. 24, 1993. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998; 64 FR 72794, Dec. 28, 1999]

§ 250.514 Well-control fluids, equipment, and operations.

(a) Well-control fluids, equipment, and operations shall be designed, utilized, maintained, and/or tested as necessary to control the well in foreseeable conditions and circumstances, including subfreezing conditions. The well shall be continuously monitored during well-completion operations and shall not be left unattended at any time unless the well is shut in and secured.

(b) The following well-control-fluid equipment shall be installed, maintained, and utilized:

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

(2) A well-control, fluid-volume measuring device for determining fluid volumes when filling the hole on trips; and

(3) A recording mud-pit-level indicator to determine mud-pit-volume gains and losses. This indicator shall include both a visual and an audible warning device.

(c) When coming out of the hole with drill pipe, the annulus shall be filled with well-control fluid before the change in such fluid level decreases the hydrostatic pressure 75 pounds per square inch (psi) or every five stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. The number of stands of drill pipe and drill collars that may be pulled prior to filling the hole and the equivalent well-control fluid volume shall be calculated and posted near the operator's station. A mechanical, volumetric, or electronic device for measuring the amount of well-control fluid required to fill the hole shall be utilized.

§ 250.515 Blowout prevention equipment.

(a) The BOP system and system components and related well-control equipment shall be designed, used, maintained, and tested in a manner nec-

essary to assure well control in foreseeable conditions and circumstances, including subfreezing conditions. The working pressure rating of the BOP system and BOP system components shall exceed the expected surface pressure to which they may be subjected. If the expected surface pressure exceeds the rated working pressure of the annular preventer, the lessee shall submit with Form MMS-124 or Form MMS-123, as appropriate, a well-control procedure that indicates how the annular preventer will be utilized, and the pressure limitations that will be applied during each mode of pressure control.

(b) The minimum BOP system for well-completion operations shall include the following:

(1) Three preventers, when the expected surface pressure is less than 5,000 psi, consisting of an annular preventer, one preventer equipped with pipe rams, and one preventer equipped with blind or blind-shear rams.

(2) Four preventers, when the expected surface pressure is 5,000 psi or greater, or for multiple tubing strings consisting of an annular preventer, two preventers equipped with pipe rams, and one preventer equipped with blind or blind-shear rams. When dual tubing strings are being handled simultaneously, dual pipe rams shall be installed on one of the pipe-ram preventers.

(3) When tapered drill string is used, the minimum BOP system shall include either of the following:

(i) Four preventers, when the expected surface pressure is less than 5,000 psi, consisting of an annular preventer, two sets of pipe rams, one capable of sealing around the larger size drill string and one capable of sealing around the smaller size drill string (one set of variable bore rams may be substituted for the two sets of pipe rams), and one preventer equipped with blind or blind shear rams; or

(ii) Five preventers, when the expected surface pressure is 5,000 psi or greater, consisting of an annular preventer, two sets of pipe rams capable of sealing around the larger size drill string, one set of pipe rams capable of sealing around the smaller size drill string (one set of variable bore rams may be substituted for one set of pipe

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rams capable of sealing around the larger size drill string and the set of pipe rams capable of sealing around the smaller size drill string), and a preventer equipped with blind or blind-shears rams.

(c) The BOP systems for well completions shall 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. No later than December 1, 1988, accumulator regulators supplied by rig air and without a secondary source of pneumatic supply, shall 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

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available for inserting valves in the work string.

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§ 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 Supervisor 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 Supervisor 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.