above the uppermost hydrocarbon-bearing zone shall be used.

(2) When a liner is to be used as production casing below intermediate casing, it shall be lapped a minimum of 100 feet into the previous casing string and cemented as required for the production casing.

§ 250.405 Pressure testing of casing.

(a) Prior to drilling the plug after cementing and in the cases of plugs in production casing strings and liners not planned to be subsequently drilled out, all casings, except the drive or structural casing, shall be pressure tested to 70 percent of the minimum internal-yield pressure of the casing or as otherwise approved or required by the District Supervisor. If the pressure declines more than 10 percent in 30 minutes or if there is another indication of a leak, the casing shall be recemented, repaired, or an additional casing string run and the casing pressure tested again. Additional remedial actions shall be taken until a satisfactory pressure test is obtained. The results of all casing pressure tests shall be recorded in the driller's report.

(b) Each production liner lap shall be tested to a minimum of 500 psi above formation fracture pressure at the shoe of the casing into which the liner is lapped, or as otherwise approved or required by the District Supervisor. The drilling liner-lap test pressure shall be equal to or exceed the pressure that will be encountered at the liner lap when conducting the planned pressure-integrity test below the liner shoe. The test results shall be recorded on the driller's report. If the test indicates an improper seal, remedial action shall be taken which provides a proper seal as demonstrated by a satisfactory pressure test.

(c) In the event of prolonged drill-pipe rotation within a casing string run to the surface or extended operations such as milling, fishing, jarring, washing over, and other operations which could damage the casing, the casing shall be pressure tested or evaluated by a logging technique such as a caliper log every 30 days. The evaluation results shall be submitted to the District Supervisor with a determination of effects of operations on the integrity of the casing for continued service during drilling operations and over the producing life of the well. If the integrity of the casing in the well has deteriorated to an unsafe level, remedial operations shall be conducted or additional casing set in accordance with a plan approved by the District Supervisor prior to continuing drilling operations.

(d) After cementing any string of casing other than the structural casing string, drilling shall not be resumed until there has been a time lapse of 8 hours under pressure for the conductor casing string and 12 hours under pressure for all other casing strings. Cement is considered under pressure if one or more float valves are shown to be holding the cement in place or when other means of holding pressure are used.

§ 250.406 Blowout preventer systems and system components.

(a) *General.* The BOP systems and system components shall be designed, installed, used, maintained, and tested to assure well control.

(b) *BOP stacks.* The BOP stacks shall consist of an annular preventer and the number of ram-type preventers as specified under paragraphs (e)(1), (f), and (g) of this section. The pipe rams shall be of a proper size(s) to fit the drill pipe in use.

(c) *Working pressure.* The working-pressure rating of any BOP component shall exceed the anticipated surface pressure to which it may be subjected. The District Supervisor may approve a lower working pressure rating for the annular preventer if the lessee demonstrates that the anticipated or actual well conditions will not place demands above its rated working pressure. (Refer to related requirements in § 250.414(f)(3)(ii) of this part.)

(d) *BOP equipment.* All BOP systems shall be equipped and provided with the following:

(1) An accumulator system which shall provide sufficient capacity to supply 1.5 times the volume of fluid necessary to close and hold closed 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 backup to the primary accumulator-charging system which shall be automatic, supplied by a power source independent from the power source to the primary accumulator-charging system, and possess sufficient capability to close all BOP components and hold them closed.

(3) At least one operable remote BOP control station in addition to the one on the drilling floor. This control station shall be in a readily accessible location away from the drilling floor.

(4) A drilling spool with side outlets if side outlets are not provided in the body of the BOP stack to provide for separate kill and choke lines.

(5) For surface BOP systems, a choke and a kill line each equipped with two full-opening valves. 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 may be installed on the kill line in lieu of the remotely controlled valve provided two readily accessible manual valves are in place and the check valve is placed between the manual valves and the pump. For subsea BOP systems, a choke and a kill line each equipped with two full-opening valves. At least one of the valves on the choke line and at least one of the valves on the kill line shall be remotely controlled.

(6) A fill-up line above the uppermost preventer.

(7) A choke manifold suitable for the anticipated pressures to which it may be subjected, method of well control to be employed, surrounding environment, and corrosiveness, volume, and abrasiveness of fluids. The choke manifold shall also meet the following requirements:

(i) Manifold and choke equipment subject to well and/or pump pressure shall have a rated working pressure at least as great as the rated working pressure of the ram-type BOP's or as otherwise approved by the District Supervisor;

(ii) All components of the choke manifold system shall be protected from the danger, if any, of freezing by heating, draining, or filling with proper fluids; and

(iii) When buffer tanks are installed downstream of the choke assemblies for the purpose of manifolding the bleed lines together, isolation valves shall be installed on each line.

(8) Valves, pipes, flexible steel hoses, and other fittings upstream of, and including, the choke manifold with pressure ratings at least as great as the rated working pressure of the ram-type BOP's or as otherwise approved by the District Supervisor.

(9) A wellhead assembly with a rated working pressure that exceeds the anticipated surface pressure to which it may be subjected.

(10) The following system components:

(i) On a conventional drilling rig, a kelly cock installed below the swivel (upper kelly cock), essentially full-opening, and a similar valve of such design that it can be run through the BOP stack (strippable) installed at the bottom of the kelly (lower kelly cock). With a mud motor in service and while using drill pipe in lieu of a kelly, one kelly cock located above and one strippable kelly cock located below the joint of drill pipe employed in lieu of a kelly. On a top-drive system equipped with a remote controlled valve, a second and lower strippable valve of a conventional kelly cock or comparable type either manually or remotely controlled. All required manual and remotely controlled valves of a kelly cock or comparable type in a top-drive system must be essentially full-opening and tested according to the test pressure and test frequency as stated in § 250.407 of this part. A wrench to fit each manually operable valve in a conventional drilling rig, mud motor, and top-drive system shall be stored in a location readily accessible to the drilling crew.

(ii) An inside BOP and an essentially full-opening drill-string safety valve in the open position on the rig floor at all times while drilling operations are being conducted. These valves shall be maintained on the rig floor to fit all connections that are in the drill string. A wrench to fit the drill-string safety valve shall be stored in a location readily accessible to the drilling crew.

(iii) A safety valve available on the rig floor assembled with the proper connection to fit the casing string being run in the hole.

(11) Locking devices installed on the ram-type preventers.

(e) *Subsea BOP requirements.* (1) Prior to drilling below surface and intermediate casing, a BOP system shall be installed consisting of at least four remote controlled, hydraulically operated BOP's including at least two equipped with pipe rams, one with blind-shear rams, and one annular type. A subsea accumulator closing unit or a suitable alternate approved by the District Supervisor is required to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface. When proposed casing setting depths or local geology indicate the need for a BOP to provide safety during the drilling of the surface hole, the District Supervisor may require that a subsea BOP system be installed prior to drilling below the conductor casing.

(2) The BOP system shall include operable dual-pod control systems necessary to ensure proper and independent operation of the BOP system functions when drilling below the surface casing.

(3) Prior to the removal of the marine riser, the riser shall be displaced with seawater. Sufficient hydrostatic pressure or other suitable precautions, such as mechanical or cement plugs or closing the BOP, shall be maintained within the wellbore to compensate for the reduction in pressure and to maintain a safe controlled well condition.

(4) Any necessary repair or replacement of the BOP system or a system component after installation shall be accomplished under safe controlled conditions, (e.g., after casing has been cemented but prior to drilling out the casing shoe or by setting a cement plug, bridge plug, or a packer).

(5) When a subsea BOP system is to be used in an area which is subject to ice scour, the BOP stack shall be placed in an excavation (glory hole) of sufficient depth to assure that the top of the stack is below the deepest probable ice-scour depth.

(f) *Surface BOP requirements.* Prior to drilling below surface or intermediate casing, a BOP system shall be installed consisting of at least four remote controlled, hydraulically operated BOP's including at least two equipped with pipe rams, one with blind rams, and one annular type.

(g) *Tapered drill-string operations.* (1) Prior to commencing tapered drill-pipe operations, the BOP stack shall be equipped with conventional and/or variable-bore pipe rams installed in two or more ram cavities to provide the following:

(i) Two sets of pipe rams capable of sealing around the larger size drill string, and

(ii) One set of pipe rams capable of sealing around the smaller size drill string.

(2) Subsea BOP systems shall have blind-shear ram capability. Surface BOP systems shall have blind ram capability.

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§ 250.407 Blowout preventer (BOP) system tests, inspections, and maintenance.

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

(1) When installed;

(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; and

(3) Before drilling out each string of casing or a liner. The District Supervisor may allow you to omit this test if you did not remove the BOP stack to run the casing string or liner and the required BOP-test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test. You must indicate in your