STATE OIL AND GAS BOARD GOVERNING SUBMERGED OFFSHORE LAND OPERATIONS ADMINISTRATIVE CODE

CHAPTER 400-2-6 PRODUCTION

TABLE OF CONTENTS

400-2-6-.01 General.

The design and construction of all wells and production facilities shall be based on sound engineering principles and must take into account the composition of the well stream, maximum pressures, and other pertinent engineering data and information. All flowing wells shall be produced through tubing anchored by a packer and shall be equipped with a master valve and adequate chokes or beans to properly control the flow thereof. The Supervisor may approve alternative procedures for properly controlling well flow, upon request by the operator.
Author: State Oil and Gas Board
Statutory Authority: Code of Ala. 1975, §§9-17-1, et seq.
History: **New Rule:** Filed April 11, 2000; effective May 16, 2000.

400-2-6-.02 Protection Of Oil And Gas.

Before any oil or gas well is completed as a producer, the producing horizons shall be sealed or separated in order to prevent their contents from passing into another stratum. Except for test purposes approved by the Supervisor, no well shall be permitted to produce oil or gas simultaneously from different strata through the same string of casing, without the permission of the Board after notice and hearing.
Author: State Oil and Gas Board
Statutory Authority: Code of Ala. 1975, §§9-17-1, et seq.

History: New Rule: Filed April 11, 2000; effective May 16, 2000.

400-2-6-.03 Initial Bottom Hole Pressure Survey.

Unless otherwise specified by the Supervisor, an operator completing a well in a new oil or gas pool(s) shall perform an initial bottom hole pressure survey on said pool(s) prior to receiving a temporary allowable from the Supervisor. The bottom hole pressure survey shall be performed with a bottom hole pressure gauge and results of the survey shall be reported to the Supervisor. The bottom hole pressure survey shall be conducted for at least twenty-four (24) hours and in accordance with industry standards.
Author: State Oil and Gas Board
Statutory Authority: Code of Ala. 1975, §§9-17-1, et seq.
History: New Rule: Filed April 11, 2000; effective May 16, 2000.

400-2-6-.04 Pressure-Volume-Temperature Analysis.

Unless otherwise specified by the Supervisor, an operator completing a well in a new oil or gas-condensate pool at a measured depth of six thousand (6,000) feet or greater shall perform a pressure-volume-temperature (PVT) analysis on a subsurface sample or recombined surface sample of hydrocarbon fluids from said well prior to receiving a temporary allowable from the Supervisor. The analysis shall be performed in accordance with industry standards and the results shall be reported to the Supervisor.
Author: State Oil and Gas Board
Statutory Authority: Code of Ala. 1975, §§9-17-1, et seq.
History: New Rule: Filed April 11, 2000; effective May 16, 2000.

400-2-6-.05 Procedures For Multiple Completions.

(1) Information shall be submitted to the Supervisor for approval showing the top and bottom of all zones proposed for completion, including a partial electrical log and a diagrammatic sketch showing such zones and equipment to be used.

(2) If zones approved for multiple completion become intercommunicated, the operator shall, after obtaining approval from the Supervisor, immediately repair the well so as to separate such zones.
Author: State Oil and Gas Board
Statutory Authority: Code of Ala. 1975, §§9-17-1, et seq.
History: New Rule: Filed April 11, 2000; effective May 16, 2000.

400-2-6-.06 Recompletion Or Reworking.

(1) Prior to commencing recompletion or reworking operations, approval shall be obtained from the Supervisor. Unless an exception is granted by the Supervisor, a proposed workover or recompletion procedure shall be submitted to the Supervisor in writing. Unless an exception is granted by the Supervisor, an operator shall submit with such procedure statements addressing the following: the reason for the workover, calculated bottom hole pressure in the well, method of controlling pressure, expected hydrogen sulfide concentrations of the well stream, blow-out preventer arrangements, and the testing requirements for blow-out preventers to be used during the operations. If the workover or recompletion is being performed on a well which contains hydrogen sulfide and the work being performed requires that the wellhead be removed, then Form OGB-24, Operator's Certificate of Compliance for Operations Involving Hydrogen Sulfide, shall accompany the workover or recompletion procedure. If the workover or recompletion is being performed on a well which contains hydrogen sulfide, then the hydrogen sulfide gas shall not be vented.

(2) If, after recompletion or reworking operations have begun, unexpected wellbore conditions are encountered the operator may, at his own risk, proceed with appropriate remedial action. As soon as practical, the Supervisor must be notified of such remedial action. Within thirty (30) days of recompletion or reworking operations, the operator shall submit a revised Form OGB-6, OGB-7, OGB-8, and OGB-9 where applicable, and one (1) copy of any additional logs.
Author: State Oil and Gas Board
Statutory Authority: Code of Ala. 1975, §§9-17-1, et seq.
History: **New Rule:** Filed April 11, 2000; effective May 16, 2000. **Amended:** Filed August 5, 2005; effective September 9, 2005.

400-2-6-.07 Subsurface Safety Devices.

(1) Safety devices and valves shall be installed, inspected, and tested, and records shall be maintained in accordance with the following requirements:

(a) All wells open to hydrocarbon-bearing zones shall be equipped with a surface-controlled subsurface safety device, installed at a depth of one hundred (100) feet or more below the waters floor. In case of failure of the surface-controlled subsurface safety device a subsurface-controlled subsurface safety device may be installed, at a depth of one hundred (100) feet or more below the waters floor, upon approval by the Supervisor. All wells in which a subsurface safety device or tubing plug is installed shall have the tubing-casing annulus packed off above the uppermost open casing perforations. The control system for all surface-controlled subsurface safety devices shall be an integral part of the platform shut-in system. In addition to the activation by manual action on the platform, the system may be activated by and shut-in by a signal from a remote location. Surface-controlled Subsurface Safety Valve's (SCSSV's) shall close in response to shut-in signals from the Emergency Shutdown Device (ESD) and in response to the fire loop or other fire detection devices.

(b) Subsurface safety devices shall be adjusted, installed, and maintained to insure reliable operation. These installations shall be made within two (2) days after stabilized production is established. The well shall be continuously attended during the stabilization period and the interval preceding the installation of the safety device. If the subsurface safety device is not installed within this two-(2-) daytime interval, or other interval specified by the Supervisor, the well shall be shut in, unless a waiver for omitting the device has been approved by the Supervisor.

1. Each subsurface-controlled subsurface safety device shall be removed, inspected, and repaired or adjusted as necessary at intervals not to exceed twelve (12) months for valves installed in a landing nipple and at intervals not to exceed six (6) months for those valves not installed in a landing nipple. Prior to installation, each device shall be repaired as necessary and adjusted or resized to compensate for changes in well conditions.

2. The subsurface safety device may be removed from a well for routine operations without authorization or notice provided the well is attended while the master valve(s) is open. The well shall not be open to flow while the subsurface safety device is removed, except when flowing of the well is necessary for routine operations. When such operations occur, the well shall be identified by a sign on the wellhead stating that the subsurface safety device has been removed.

3. Each surface-controlled subsurface safety valve shall be tested in place for proper operation when installed or reinstalled and thereafter at intervals not exceeding six (6) months. Testing shall be in accordance with API RP 14B, and subsequent revisions thereof, to ensure proper operation. However, the Supervisor may require more frequent inspection and testing of these devices or valves. Prior to installation, each device shall be repaired as necessary and adjusted or resized to compensate for changes in well conditions.

(c) In all tubing installations, the tubing string shall be equipped with a landing nipple to provide for the setting of the subsurface safety device. New completions (perforated but not placed on production) and completions shut in for a period of one (1) year shall be equipped with either:

1. a pump-through-type tubing plug;

2. a surface-controlled SCSSV, provided the surface control has been rendered inoperative; or

3. an injection valve capable of preventing back flow. In lieu of, or in addition to, other subsurface safety devices such devices shall be set at a depth of one hundred (100) feet or more below the waters floor.

(d) In the event well conditions prevent, or make impractical the installation of subsurface safety devices, the operator may submit in writing a request for a waiver of the requirement for the installation of such a device, including a detailed statement of the efforts made to overcome the difficulties and, if possible, an alternate safety measure.

1. The Supervisor may require a different program under the following conditions:

(i) When artificial lift is required;

(ii) When the flowing tubing pressure at the wellhead is too low to permit adjustment of the safety device for proper operation;

(iii) When the subsurface device causes sand to plug the tubing or sand makes the subsurface safety device inoperative;

(iv) When flow rate fluctuation or water production prevents a well equipped with a subsurface device from producing;

(v) When the mechanical condition of the well does not permit the installation of a subsurface safety device or at the prescribed minimum depth under section (a) above;

(vi) Class II injection wells; and

(vii) Underground storage wells.

(e) **Emergency Action.** In the event of an emergency, such as an impending storm, any well not equipped with a subsurface safety device and which is capable of natural flow shall have the device properly installed as soon as possible with due consideration being given to personnel safety.

(f) The well completion report and any subsequent report of workover shall state the type and the depth of the subsurface safety device installed in the well or state that the requirement has been waived.

(g) The operator shall maintain records showing the present status and past history of each subsurface safety device, or automatic surface shut in device installed in lieu of a subsurface safety device, including pressure settings and setting depths (if applicable), and dates and details of inspections, testing, repairing, adjustment, installations and bench tests. Records shall be retained for a period of two (2) years during which time they shall be available for review by the Supervisor.

Author: State Oil and Gas Board
Statutory Authority: Code of Ala. 1975, §§9-17-1, et seq.
History: **New Rule:** Filed April 11, 2000; effective May 16, 2000.

400-2-6-.08 Wellhead Equipment And Testing Procedures.

(1) **Wellhead equipment.**

(a) All completed wells shall be equipped with casing heads, wellhead fittings, valves and connections with a rated working-pressure greater than the surface shut-in pressure of the well. Prior to production, the production casing shall be tested to the shut-in tubing pressure with a fluid approved by the Supervisor. When the wellhead is installed, the tree shall be equipped so that the pressures on all annuli can be continuously monitored. Each casing annulus shall have an established maximum pressure limit, which shall be approved by the Supervisor. The maximum allowable pressure for each casing annulus shall be posted near the casing or wellhead. The Supervisor shall be notified if the pressure exceeds, by ten percent (10%), the maximum pressure set for the casing string. Positive pressure shall be maintained on all annuli while producing the well. This pressure may be maintained by repressuring the casing with an approved fluid or inert gas such as nitrogen. All casing annuli pressures shall be continuously monitored and the pressures recorded. The pressure on each casing annulus shall be recorded daily and the maximum pressure each casing annulus reaches during the calendar month shall be reported to the Supervisor quarterly. Connections and valves shall be designed to permit fluid to be pumped between any two strings of casing, unless otherwise approved by the Supervisor. Two master valves shall be installed on the tubing in wells with a surface shut-in pressure in excess of five thousand (5,000) pounds per square inch (psi). All wellhead connections shall be assembled and tested prior to installation by a fluid pressure, which shall be equal to the rated working pressure of the fitting to be installed.

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

(2) **Abnormal Casing Pressure/Leak Testing.** Any well showing abnormal pressure on the casinghead or leaking gas or oil between production casing and the next larger string of casing, shall be immediately reported to the Supervisor and shall be monitored and evaluated for the source of the pressure and leak. A diagnostic test including bleed down through a needle valve and buildup to record the pressures in at least one (1)-hour increments shall be performed on each casing string in the wellbore found with abnormal casing pressure. Wells with abnormal casinghead pressure that is less than twenty percent (20%) of the minimum internal yield pressure of the affected casing and that bleed to zero (0) pounds per square inch (psi) pressure through a needle valve in twenty-four (24) hours or less may continue producing operations from the present completion. Requests for wells having casings with abnormal pressure more than twenty percent (20%) of the minimum internal yield pressure of the affected casing or pressure that does not bleed to zero (0) psi through a needle valve, shall be submitted to the Supervisor for approval to continue producing operations from the present completion. The operator shall comply with any additional diagnostic testing the Supervisor may require. Complete data on each well's casing pressure shall be maintained for a period of two (2) years. If the conditions cannot be corrected, the well shall be killed.
Author: State Oil and Gas Board
Statutory Authority: Code of Ala. 1975, §§9-17-1, et seq.
History: New Rule: Filed April 11, 2000; effective May 16, 2000.

400-2-6-.09 Platforms And Fixed Structures.

(1) **General.** The location, design, and installation of all platforms and fixed structures shall include consideration of such factors as shallow hazards on and immediately underlying the waters floor, water depths, soil conditions, wave and current forces, wind forces, total equipment weight, and other pertinent geological, geographical, environmental, and operational conditions.

(2) **Design Features.** At least thirty (30) days prior to installing any platform or fixed structure, the operator shall submit for approval by the Supervisor design features applicable to the exact

location and primary intended use or uses of such platform or fixed structure including a certification and plats showing:

(a) Platform dimensions (plan view and two elevations);

(b) Nominal size and thickness range of piling;

(c) Nominal size and thickness range of jacket column leg;

(d) Nominal size and thickness range of deck column leg;

(e) Design piling penetration;

(f) Maximum bearing and lateral load per pile in tons;

(g) Number and location of well slots;

(h) Water depths; and

(i) Plat showing the location of living quarters, evacuation routes, boat landings, heliports, and cranes.

(j) The following certification signed and dated with the title of the company representative: "(Operator) certifies that the design of (platform or structure and identification number) has been approved by a registered professional engineer having a specialty in structural engineering or registered civil engineer specializing in structural design."

(k) Any structural modification to a platform or fixed structure shall be submitted for approval by the Supervisor prior to making such modification. The operator shall recertify the modified structure.

(l) Additional information when required by the Supervisor.

(3) **Shallow Hazards.** In accordance with Rule 400-2-8-.01, relating to Survey of Shallow Hazards, an operator shall file two (2) copies of a report of shallow hazards with the information required to be submitted in accordance with (2) above.

(4) **Recertification of Structural Integrity.** Periodic inspections and proper maintenance shall be performed to assure the structural integrity of each platform or fixed structure. Unless otherwise approved by the Supervisor, the structural integrity of each platform or fixed structure shall be recertified every five years. Recertifications of platforms and fixed structures shall be submitted to the Supervisor and shall include a written report of inspections performed in accordance with API RP 2A, and subsequent revisions thereof, and the following certification signed and dated with the title of the company representative: "(Operator) certifies that (platform or structure and identification number) has been inspected in accordance with API RP 2A, and subsequent

revisions thereof, and the structural integrity of the (platform or fixed structure) has been verified by a registered professional engineer having a specialty in structural engineering or registered civil engineer specializing in structural design."
Author: J. H. Masingill
Statutory Authority: Code of Ala. 1975, §§9-17-1, et seq.
History: New Rule: Filed April 11, 2000; effective May 16, 2000.
Amended: Filed November 17, 2003; effective December 22, 2003.

400-2-6-.10 Production Facilities, Processing Facilities, And Offshore Plants.

Onshore facilities processing hydrocarbons produced from submerged offshore lands are subject to this rule. All offshore production facilities, processing facilities, and offshore plants shall be designed, installed, and maintained in a manner which provides for efficiency, safety of operation, and protection of the environment. All information required for the Supervisor's approval in this rule shall be submitted at least thirty (30) days prior to installation.

(1) **Production Facilities.**

(a) All production equipment shall be designed, installed, and maintained in accordance with generally accepted industry practices or standards.

(b) A generalized process schematic flow diagram showing all equipment with size, capacity, and design working pressure of separators, flare scrubbers, treaters, storage tanks, compressors, line pumps, metering devices, and other hydrocarbon-handling vessels, and the location of safety and pollution control equipment shall be submitted to the Supervisor for approval.

(c) Prior to construction and operation of a sour gas production facility, approval must be obtained from the Supervisor. Application for permission to construct and operate a sour gas production facility shall be considered a two-step process.

1. **Step 1.** An operator seeking the Supervisor's approval for the construction and operation of a sour gas production facility shall submit in duplicate the information listed below:

(i) A generalized schematic flow diagram showing all equipment on location with size, capacity, and design working pressure of separators, flare scrubbers, treaters, storage tanks, compressors, line pumps, metering devices, and other hydrocarbon-handling vessels, and the location of safety and pollution control equipment.

(ii) A description and schematic diagram showing hydrogen sulfide safety and monitoring equipment specified in Rule 400-2-8-.04 relating to Operations Involving Hydrogen Sulfide.

2. **Step 2.** Prior to placing equipment in service, the following information shall be submitted:

(i) The following certification signed and dated with the title of the company representative: "(Operator) certifies that the (Production Facility) has been designed, installed and will be operated in accordance with generally accepted industry practices or standards for such facilities."

(ii) In accordance with Rule 400-2-8-.04 relating to Operations Involving Hydrogen Sulfide, an Operator's Certificate of Compliance for Operations Involving Hydrogen Sulfide on Form OGB-24 for the facility, and associated wells, shall be submitted to the Supervisor.

(d) Additional information when required by the Supervisor.

(2) **Processing Facilities.**

(a) Processing facilities shall be designed, installed, and maintained in accordance with generally accepted industry practices or standards.

(b) Prior to the construction and operation of a processing facility, approval must be obtained from the Supervisor. Application for permission to construct and operate a processing facility shall be considered as a two-step process.

1. **Step 1.** An operator seeking the Supervisor's approval for the design and construction of a processing facility shall submit in duplicate the information listed below:

(i) A plat of the site.

(ii) A generalized statement of processes and procedures used in the facility and the design capacity of the facility.

(iii) A generalized schematic flow diagram showing all equipment on location and a plat showing location, size, capacity, and design working pressure of separators, flare scrubbers, treaters, storage tanks, compressors, line pumps, metering devices, and other hydrocarbon-handling vessels, and the location of safety and pollution control equipment.

(iv) Generalized schematic diagrams showing location of hydrogen sulfide and combustible gas detection equipment, sensors and alarms, personnel safety equipment, fire fighting equipment, and emergency shutdown devices.

(v) Construction plans and schedules shall be submitted to the Supervisor prior to initiating construction of the facility.

2. **Step 2.** Prior to placing a processing facility into service, the following certification signed and dated with the title of the company representative shall be submitted: "(Operator) certifies that the (Processing Facility) has been designed, installed and will be operated to meet or exceed generally accepted industry standards or practices for such facilities."

(c) Notification shall be given to the Supervisor for turnaround operations.

(d) For sour gas operations, in addition to the above, the following information shall be submitted:

1. A description and schematic diagram showing hydrogen sulfide safety and monitoring equipment specified in Rule 400-2-8-.04 relating to Operations Involving Hydrogen Sulfide.

2. Operator's Certificate of Compliance for Operations Involving Hydrogen Sulfide on Form OGB-24 for the facility, and associated wells, shall be submitted to the Supervisor.

(e) Additional information when required by the Supervisor.

(3) **Offshore Plant.**

(a) An offshore plant shall be designed, installed, and maintained in accordance with generally accepted industry practices or standards.

(b) Prior to the construction and operation of an offshore plant, approval must be obtained from the Supervisor. Application for permission to construct and operate an offshore plant shall be considered as a two-step process.

1. **Step 1.** An operator seeking the Supervisor's approval for the design and construction of an offshore plant shall submit in duplicate the information listed below:

(i) A plat of the site.

(ii) A generalized statement of processes and procedures used in the facility and the design capacity of the facility.

(iii) A generalized schematic flow diagram showing all equipment on location and a plat showing location, size, capacity, and design working pressure of separators, flare scrubbers, treaters, storage tanks, compressors, line pumps, metering devices, and other hydrocarbon-handling vessels, and the location of safety and pollution control equipment.

(iv) Generalized schematic diagrams showing location of hydrogen sulfide and combustible gas detection equipment, sensors and alarms, personnel safety equipment, fire fighting equipment, and emergency shut- down devices.

(v) Construction plans and schedules shall be submitted to the Supervisor prior to initiating construction of the facility.

2. **Step 2.** Prior to placing the offshore plant in service the operator shall submit information pertaining to operation and maintenance as listed below:

(i) The operator shall submit a schedule for initial testing and inspection of the safety systems at the offshore plant. Such test shall be witnessed by the Board's representative prior to commencing the operation of the offshore plant. Schedules for subsequent inspections and testing shall be submitted to the Supervisor.

(ii) Gas monitoring equipment, including equipment for hydrogen sulfide monitoring and combustible gas detection, shall be maintained in accordance with industry standards.

(iii) The operator shall maintain records showing the dates and results of inspection, testing, repairing, adjustment, and reinstallation of all shut-in devices, relief valves, and safety systems for a period of two (2) years, during which time they shall be available for review by an agent of the Board.

(iv) Prior to placing an offshore plant into service, the following certification signed and dated with the title of the company representative shall be submitted: "(Operator) certifies that the (Offshore Plant) has been designed, constructed and will be operated to meet or exceed generally accepted industry practices or standards for such facilities."

(c) Prior to placing an offshore plant involving extraction, into service, approval must be obtained from the Board after notice and hearing.

(d) Notification shall be given to the Supervisor for turnaround operations.

(e) For sour gas operations, in addition to the above, the following information shall be submitted:

1. A description and schematic diagram showing hydrogen sulfide safety and monitoring equipment specified in Rule 400-2-8-.04, relating to Operations Involving Hydrogen Sulfide.

2. Operator's Certificate of Compliance for Operations Involving Hydrogen Sulfide on Form OGB-24 for the facility and associated wells shall be submitted to the Supervisor.

(f) Additional information when required by the Supervisor.

(4) **Modifications to Production Facilities, Processing Facilities, and Offshore Plants.** Modifications to production facilities, processing facilities, and offshore plants shall be addressed in the following manner:

(a) If any production facility requires modifications or metering changes that revise the basic information pertaining to flow diagrams or treatment, revised schematics shall be submitted to the Supervisor for his approval prior to making such modifications.

(b) If any sour gas production facility, processing facility or offshore plant requires modifications or metering changes that revise the basic information pertaining to flow diagrams, processing, safety systems, or equipment size and locations, revised schematics shall be submitted to the Supervisor for the approval prior to making such modifications.

(c) Additional information when required by the Supervisor.

(5) **Safety and Pollution Control Equipment and Procedures.** All platform production facilities, processing facilities, and offshore plants shall be protected with a basic and ancillary surface safety system designed, analyzed, installed, tested, and maintained in operating condition in accordance with the provisions of API RP 14C, or subsequent revisions thereof, and in accordance with the following:

(a) All pressure vessel relief valves shall be connected to a flare line.

(b) All pressure sensors and all pressure relief valves shall be equipped to permit testing with an external pressure source. A relief valve shall be set no higher than the designed working pressure of the vessel. The high-pressure shut-in sensor shall be set no higher than five percent (5%) or five (5) pounds per square inch (psi), whichever is greater, below the rated or designed working pressure of the vessel. The low pressure shut-in sensor shall be set no lower than fifteen percent (15%) or 5 psi, whichever is greater below the lowest pressure in the operating pressure range. The activation of low-pressure sensors on pressure vessels that operate at less than 5 psi shall be approved by the Supervisor.

(c) All flare lines shall be equipped with a scrubber or similar separation equipment capable of handling the rated capacity of the vessel on the platform.

(d) All wellhead assemblies shall be equipped with an automatic fail-close valve. Automatic safety valves temporarily out of service shall be flagged.

(e) Flowlines from wells shall be equipped with high- and low-pressure shut-in sensors located in accordance with Figure A1 of API RP 14C, or subsequent revisions thereof.

(f) All shut-in systems shall be activated by fusible material as specified by Table C1 of API RP 14C, or subsequent revisions thereof.

(g) The Emergency Shutdown Device (ESD) shall conform to the requirements of Appendix C, Section C1, of API RP 14C, or subsequent revisions thereof. The manually operated ESD valve(s) shall be quick opening and nonrestricted to enable the rapid actuation of the shutdown system.

(h) The following safety devices shall be tested monthly for the first four (4) months after being placed in service.

1. All Pressure Sensor High (PSH) or Pressure Sensor Low (PSL),

2. All Level Sensor High (LSH) and Level Sensor Low (LSL) controls,

3. All automatic inlet Shutdown Valves (SDV's) which are actuated by a sensor on a vessel or compressor, and

4. All SDV's in liquid discharge lines and actuated by vessel low-1evel sensors.

(i) If the monthly results are consistently within test tolerance, a quarterly test shall be required for at least one (1) year. If these results are consistently within test tolerance, upon request of the operator, a longer period of time between testing may be considered for approval by the Supervisor.

(j) All automatic wellhead safety valves shall be tested monthly for operation. If these results are consistently within test tolerance, a longer period of time between pressure tests, not to exceed quarterly, may be considered for approval by the Supervisor.

(k) All flowline check valves shall be tested monthly for leakage for the first four (4) months after being placed in service. If the monthly results are consistently within test tolerance, quarterly tests shall be required for at least one (1) year. If these results are consistently within test tolerance, or upon request of the operator, a longer period of time between tests may be considered for approval by the Supervisor.

(l) A complete testing and inspection of the safety system shall be witnessed by the Supervisor’s representative at the time production is commenced. Thereafter, the operator shall arrange for a test every twelve- (12-) months. The test shall be conducted when it can be witnessed by the Supervisor’s representative.

(m) The operator shall maintain records showing the dates and results of inspection, testing, repairing, adjustment and reinstallation of all surface and subsurface safety devices for a period of two (2) years, during which time they shall be available for review by the Supervisor.

(n) Additional information when required by the Supervisor.

(6) **Fire Fighting System.** A fire fighting system shall be installed in accordance with the following:

(a) A fire fighting system shall be installed in conformance with Subsection 5.2, Fire Water Systems, of API RP14G, or subsequent revisions thereof. The firewater system shall consist of rigid pipe with fire hose stations or fixed firewater monitors and shall be installed in all areas where hydrocarbon production equipment is located. A fire fighting system using chemicals may be installed in lieu of a firewater system if it is determined that it will provide equivalent fire protection. A fixed water spray system shall be installed in enclosed well-bay areas where hydrocarbon vapors may accumulate.

(b) Fuel or power for firewater pump drivers shall be available for at least thirty (30) minutes of run time during platform shut-in time. If necessary, an alternate fuel or power supply shall be installed to provide continued pump operation during platform shut down unless an alternate fire fighting system is provided.

(c) Portable fire extinguishers shall be placed in conformance with Subsection 6.2, Placement of Extinguishers, of API RP14G, or subsequent revisions thereof.

(d) The fire fighting system and all portable fire extinguishers shall be inspected and maintained in conformance with Section 7, Inspection, Testing, and Maintenance, of API RP14G, or subsequent revisions thereof. A record of testing shall be retained for a period of two (2) years during which time they shall be available for review by the Supervisor.

(e) A diagram of the fire fighting system showing the location of all equipment shall be posted in a prominent place on the platform or structure.

(f) Additional information when required by the Supervisor.

(7) **Automatic Detector and Alarm System.** Fire and gas detection systems shall be capable of continuous monitoring. Fire-detection systems and portions of combustible gas-detection systems related to the higher gas concentration

levels shall be of the manual-reset type. Combustible gas-detection systems related to the lower gas-concentration level may be of the automatic-reset type.

(a) Gas detection systems shall be installed in all enclosed areas containing gas handling facilities or equipment and in other enclosed areas which are not adequately ventilated as defined in Section C1.3b. of API RP14C, or subsequent revisions thereof.

(b) Fire and gas detection systems shall be an approved type, designed and installed in accordance with API RP14C, RP14G, and RP14F, or subsequent revisions thereof.

(c) The central control shall be capable of initiating an alarm at a maximum of twenty-five (25%) of the lower explosive limit (LEL). This low level shall be for alarm purposes only.

(d) A high level setting of no greater than sixty percent (60%) LEL shall initiate appropriate sequences on the platform or structure.

(e) Fire (flame, heat, or smoke) sensors shall be installed in all enclosed classified areas.

(f) Additional information when required by the Supervisor.

(8) **Electrical Equipment and Systems.** The following requirements shall be applicable to all electrical equipment and systems installed on platforms, fixed structures, and mobile drilling facilities:

(a) All electrical generators, motors, and lighting systems shall be installed, protected and maintained in accordance with the most current edition of the National Electrical Code and API RP 500, or subsequent revisions thereof.

(b) Marine-armored cable or metal-clad cable may be substituted for wire in conduit in any area.

(c) Additional information when required by the Supervisor.

(9) **Certification.** The following certification signed and dated with the title of the company representative: "(Operator) certifies that the design and installation of the safety and pollution control equipment and procedures in section (5), the fire fighting system in section (6), the automatic detector and alarm system in section (7), and the electrical equipment and systems in section (8), to be

installed on (platform or structure identification number) have been approved by qualified personnel including a registered professional engineer(s) and that future modifications and maintenance of these systems will be in accordance with acceptable industry standards."

Author: State Oil and Gas Board
Statutory Authority: Code of Ala. 1975, §§9-17-1, et seq.
History: **New Rule:** Filed April 11, 2000; effective May 16, 2000.
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Previous Chapter 400-2 (Rules 400-2-X-.01 through 400-2-X-.09) Repealed and New Chapters 400-2-1 through 400-2-9 adopted in lieu thereof: Filed April 11, 2000.