DEPARTMENT OF THE INTERIOR

Bureau of Safety and Environmental Enforcement

30 CFR Part 250

[Docket ID: BSEE–2012–0005; 13XE1700DX EX1SF0000.DAQ000 EEEE500000]

RIN 1014–AA10

Oil and Gas and Sulphur Operations on the Outer Continental Shelf—Oil and Gas Production Safety Systems

AGENCY: Bureau of Safety and Environmental Enforcement (BSEE), Interior.

ACTION: Proposed rule.

SUMMARY: The Bureau of Safety and Environmental Enforcement (BSEE) proposes to amend and update the regulations regarding oil and natural gas production by addressing issues such as: Safety and pollution prevention equipment lifecycle analysis, production safety systems, subsurface safety devices, and safety device testing. The proposed rule would differentiate the requirements for operating dry tree and subsea tree production systems on the Outer Continental Shelf (OCS) and divide the current subpart H into multiple sections to make the regulations easier to read and understand. The changes in this proposed rule are necessary to bolster human safety, environmental protection, and regulatory oversight of critical equipment involving production safety systems.

DATES: Submit comments by October 21, 2013. The BSEE may not fully consider comments received after this date. You may submit comments to the Office of Management and Budget (OMB) on the information collection burden in this proposed rule by September 23, 2013. The deadline for comments on the information collection burden does not affect the deadline for the public to comment to BSEE on the proposed regulations.

ADDRESSES: You may submit comments on the rulemaking by any of the following methods. Please use the Regulation Identifier Number (RIN) 1014–AA10 as an identifier in your message. See also Public Availability of Comments under Procedural Matters.

- Federal eRulemaking Portal: *http://www.regulations.gov.* In the entry titled Enter Keyword or ID, enter BSEE–2012–0005 then click search. Follow the instructions to submit public comments and view supporting and related materials available for this rulemaking. The BSEE may post all submitted comments.
- Mail or hand-carry comments to the Department of the Interior (DOI); Bureau of Safety and Environmental Enforcement; Attention: Regulations Development Branch; 381 Elden Street, HE3313; Herndon, Virginia 20170–4817. Please reference ''Oil and Gas Production Safety Systems, 1014–AA10'' in your comments and include your name and return address.
- Send comments on the information collection in this rule to: Interior Desk Officer 1014–0003, Office of Management and Budget; 202–395–5806 (fax); email: *oira_submission@omb.eop.gov.* Please send a copy to BSEE.
- Public Availability of Comments—Before including your address, phone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

FOR FURTHER INFORMATION CONTACT: Kirk Malstrom, Regulations Development Branch, 703–787–1751, *kirk.malstrom@bsee.gov.*

SUPPLEMENTARY INFORMATION:

Executive Summary

This proposed rule would amend and update the Subpart H, Oil and Gas Production Safety Systems regulations. Subpart H has not had a major revision since it was first published in 1988. Since that time, much of the oil and gas production on the OCS has moved into deeper waters and the regulations have not kept pace with the technological advancements.

These regulations address issues such as production safety systems, subsurface safety devices, and safety device testing. These systems play a critical role in protecting workers and the environment. The BSEE would make the following changes to Subpart H in this rulemaking:

- Restructure the subpart to have shorter, easier-to-read sections based on the following headings:
  - General requirements;
  - Surface and subsurface safety systems—Dry trees;
  - Subsea and subsurface safety systems—Subsea trees;
  - Production safety systems;
  - Additional production system requirements;
  - Safety device testing; and
  - Records and training.
- Update and improve the safety and pollution prevention equipment (SPPE) lifecycle analysis in order to increase the overall level of certainty that this equipment would perform as intended including in emergency situations. The lifecycle analysis involves vigilance throughout the entire lifespan of the SPPE, including design, manufacture, operational use, maintenance, and eventual decommissioning of the equipment. A major component of the lifecycle analysis involves the proper documentation of the entire process. The documentation allows an avenue for continual improvement throughout the life of the equipment by evaluation of mechanical integrity and communication between equipment operators and manufacturers.
- Expand the regulations to differentiate the requirements for operating dry tree and subsea tree production systems on the OCS.
- Incorporate new industry standards and update the incorporation of partially incorporated standards to require compliance with the complete standards.
- Add new requirements for, but not limited to, the following:
  - SPPE life cycle and failure reporting;
  - Foam firefighting systems;
  - Electronic-based emergency shutdown systems (ESDs);
  - Valve closure timing;
  - Valve leakage rates;
  - Boarding shut down valves (BSDV); and
  - Equipment used for high temperature and high pressure wells.
- Rewrite the subpart in plain language according to:
  - The Plain Writing Act of 2010;
  - Executive Order 12866;
  - Executive Order 12988; and
  - Executive Order 13563, *Improving Regulation and Regulatory Review.*

In addition to Subpart H revisions, we would revise the regulation in Subpart A requiring best available and safest technology (BAST) to follow more closely the Outer Continental Shelf Lands Act's (OCSLA, or the Act) statutory provision for BAST, 43 U.S.C. 1347(b).

Review of Proposed Rule

This rulemaking proposes a complete revision of the regulations at 30 CFR Part 250, Subpart H—Oil and Gas Production Safety Systems. The current regulations were originally published on April 1, 1988 (53 FR 10690). Since that time, various sections were updated, and BSEE has issued several Notices to

Lessees (NTLs) to clarify the regulations and to provide guidance. The new version of subpart H would represent a major improvement in the structure and readability of the regulation with new changes in the requirements.

Organization

The proposed rule would restructure Subpart H. The new version is divided into shorter, easier-to-read sections. These sections are more logically organized, as each section focuses on a single topic instead of multiple topics found in each section of the current regulations. For example, in the current regulations, all requirements for subsurface safety devices are found in one section (§ 250.801). In the proposed rule, requirements for subsurface safety devices would be contained in 27 sections (§§ 250.810 through 250.839), with the sections organized by general requirements and requirements related to the use of either a dry or subsea tree. The groupings in the proposed rule would make it easier for an operator to find the information that applies to a particular situation. The numbering for proposed Subpart H would start at § 250.800, and end at § 250.891. The proposed rule would separate Subpart H into the following undesignated headings:

- General Requirements
- Surface and Subsurface Safety Systems—Dry Trees
- Subsea and Subsurface Safety Systems—Subsea Trees
- Production Safety Systems
- Additional Production System Requirements
- Safety Device Testing
- Records and Training

Major Changes to the Rule

Typically, well completions associated with offshore production platforms are characterized as either dry tree (surface) or subsea tree completions. The ''tree'' is the assembly of valves, gauges, and chokes mounted on a well casinghead used to control the production and flow of oil or gas. Dry tree completions are the standard for OCS shallow water platforms, with the tree in a ''dry'' state located on the deck of the production platform. The dry tree arrangement allows direct access to valves and gauges to monitor well conditions, such as pressure, temperature, and flow rate, as well as direct vertical well access. As oil and gas production moved into deeper water, dry tree completions, because they are easily accessible, were still used on new types of platforms more suitable for deeper waters; such as compliant towers, tension-leg platforms, and spars. Starting with Conoco's Hutton tension-leg platform installed in the North Sea in 1984 in approximately 486 feet of water, these platform types gradually extended the depth of usage for dry tree completions to over 4,600 feet of water depth.

Production in the Gulf of Mexico now occurs in depths of 9,000 feet of water, with many of the wells producing from water depths greater than 4,000 feet utilizing ''wet'' or subsea trees. With a subsea tree completion the tree is located on the seafloor. These subsea completions are generally tied back to floating production platforms, and from there the production moves to shore through pipelines. Due to the location on the seafloor, subsea trees or subsea completions do not allow for direct access to valves and gauges, but the pressure, temperature, and flow rate from the subsea location is monitored from the production platform and in some cases from onshore data centers. In conjunction with all production operations and completions, there are associated subsurface safety devices designed to prevent uncontrolled releases of reservoir fluid or gas.

Subpart H has not kept pace with industry's use of subsea trees and other technologies that have evolved or become more prevalent offshore over the last 20 years. This includes items as diverse as foam firefighting systems; electronic-based ESDs; subsea pumping, waterflooding, and gaslift; and new alloys and equipment for high temperature and high pressure wells.

Another major change to the regulations in this proposed rule involves the lifecycle analysis of SPPE. The lifecycle analysis of SPPE is not a new concept and its elements are discussed in several industry documents incorporated in this rule, such as American Petroleum Institute (API) Spec. 6a, API Spec. 14A, API Recommended Practice (RP) 14B, and corresponding International Organization for Standardization (ISO) 10432 and ISO 10417. This proposed rule would codify aspects of the lifecycle analysis into the regulations and bring attention to its importance. The lifecycle analysis involves careful consideration and vigilance throughout SPPE design, manufacture, operational use, maintenance, and decommissioning of the equipment. Lifecycle analysis is a tool for continual improvement throughout the life of the equipment.

To assist in locating the regulations, the following table shows how sections of the proposed rule correspond to provisions of the current regulations in Subpart H:

Current regulation	Proposed rule
§ 250.800 General requirements	§ 250.800 General.
§ 250.801 Subsurface safety devices	§ 250.810 Dry tree subsurface safety devices—general. § 250.811 Specifications for subsurface safety valves (SSSVs)—dry trees. § 250.812 Surface-controlled SSSVs—dry trees. § 250.813 Subsurface-controlled SSSVs. § 250.814 Design, installation, and operation of SSSVs—dry trees. § 250.815 Subsurface safety devices in shut-in wells—dry trees. § 250.816 Subsurface safety devices in injection wells—dry trees. § 250.817 Temporary removal of subsurface safety devices for routine operations. § 250.818 Additional safety equipment—dry trees. § 250.821 Emergency action. § 250.825 Subsea tree subsurface safety devices—general. § 250.826 Specifications for SSSVs—subsea trees. § 250.827 Surface-controlled SSSVs—subsea trees. § 250.828 Design, installation, and operation of SSSVs—subsea trees. § 250.829 Subsurface safety devices in shut-in wells—subsea trees. § 250.830 Subsurface safety devices in injection wells—subsea trees. § 250.832 Additional safety equipment—subsea trees. § 250.837 Emergency action and safety system shutdown.

Current regulation	Proposed rule
§ 250.802 Design, installation, and operation of surface production-safety systems.	§ 250.819 Specification for surface safety valves (SSVs). § 250.820 Use of SSVs. § 250.833 Specification for underwater safety valves (USVs). § 250.834 Use of USVs. § 250.840 Design, installation, and maintenance—general. § 250.841 Platforms. § 250.842 Approval of safety systems design and installation features.
§ 250.803 Additional production system requirements	§ 250.850 Production system requirements—general. § 250.851 Pressure vessels (including heat exchangers) and fired vessels. § 250.852 Flowlines/Headers. § 250.853 Safety sensors. § 250.855 Emergency shutdown (ESD) system. § 250.856 Engines. § 250.857 Glycol dehydration units. § 250.858 Gas compressors. § 250.859 Firefighting systems. § 250.862 Fire and gas-detection systems. § 250.863 Electrical equipment. § 250.864 Erosion. § 250.869 General platform operations. § 250.871 Welding and burning practices and procedures.
§ 250.804 Production safety-system testing and records	§ 250.880 Production safety system testing. § 250.890 Records.
§ 250.805 Safety device training	§ 250.891 Safety device training.
§ 250.806 Safety and pollution prevention equipment quality assurance requirements.	§ 250.801 Safety and pollution prevention equipment (SPPE) certification. § 250.802 Requirements for SPPE.
§ 250.807 Additional requirements for subsurface safety valves and related equipment installed in high pressure high temperature (HPHT) environments.	§ 250.804 Additional requirements for subsurface safety valves (SSSVs) and related equipment installed in high pressure high temperature (HPHT) environments.
§ 250.808 Hydrogen sulfide.	§ 250.805 Hydrogen sulfide.
New Sections	§ 250.803 What SPPE failure reporting procedures must I follow? § 250.831 Alteration or disconnection of subsea pipeline or umbilical. § 250.835 Specification for all boarding shut down valves (BSDV) associated with subsea systems. § 250.836 Use of BSDVs § 250.838 What are the maximum allowable valve closure times and hydraulic bleeding requirements for an electro-hydraulic control system? § 250.839 What are the maximum allowable valve closure times and hydraulic bleeding requirements for a direct-hydraulic control system? § 250.854 Floating production units equipped with turrets and turret mounted systems. § 250.860 Chemical firefighting system. § 250.861 Foam firefighting system. § 250.865 Surface pumps. § 250.866 Personal safety equipment. § 250.867 Temporary quarters and temporary equipment. § 250.868 Non-metallic piping. § 250.870 Time delays on pressure safety low (PSL) sensors. § 250.872 Atmospheric vessels. § 250.873 Subsea gas lift requirements. § 250.874 Subsea water injection systems. § 250.875 Subsea pump systems. § 250.876 Fired and Exhaust Heated Components.

Availability of Incorporated Documents for Public Viewing

When a copyrighted technical industry standard is incorporated by reference into our regulations, BSEE is obligated to observe and protect that copyright. The BSEE provides members of the public with Web site addresses where these standards may be accessed for viewing—sometimes for free and sometimes for a fee. The decision to charge a fee is decided by the standard developing organizations. The American Petroleum Institute (API) will provide free online public access to 160 key industry standards, including a broad range of technical standards. The standards available for public access represent almost one-third of all API standards and include all that are safety-related or have been incorporated into Federal regulations, including the standards in this rule. These standards are available for review, and hardcopies and printable versions will continue to be available for purchase. We are proposing to incorporate API standards in this proposed rule, and the address to the API Web site is: *http://publications.api.org/documentslist.aspx*. You may also call the API Standard/Document Contact IHS at 1–800–854–7179 or 303–397–7956 local and international.

For the convenience of the viewing public who may not wish to purchase or view these proposed documents online, they may be inspected at the Bureau of Safety and Environmental Enforcement, 381 Elden Street, Room 3313, Herndon, Virginia 20170; phone: 703–787–1587; or at the National Archives and Records Administration (NARA).

For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html*.

These documents, if incorporated in the final rule, would continue to be made available to the public for viewing when requested. Specific information on where these documents can be inspected or purchased can be found at 30 CFR 250.198, Documents Incorporated by Reference.

Section-by-Section Discussion

The following is a brief section-by-section description of the substantive proposed changes to subpart H, as well as other sections of the proposed rule. In several of the section descriptions below, BSEE requests comments on particular issues raised by that section.

What must I do to protect health, safety, property, and the environment? (§ 250.107)

The proposed rule would revise portions of § 250.107 related to the use of best available and safest technology (BAST) by revising paragraph (c) and removing paragraph (d). The intent of the change is to more closely track the BAST provision in the OCSLA. That statutory provision requires:

> on all new drilling and production operations and, wherever practicable, on existing operations, the use of the best available and safest technologies which the Secretary determines to be economically feasible, wherever failure of equipment would have a significant effect on safety, health, or the environment, except where the Secretary determines that the incremental benefits are clearly insufficient to justify the incremental costs of utilizing such technologies (43 U.S.C. 1347(b).)

Existing § 250.107(c) requires the use of BAST ''whenever practical'' on ''all exploration, development, and production operations.'' Moreover, it provides that compliance with the regulations generally is considered to be the use of BAST. The existing provision is problematic for a number of reasons. The use of the phrase ''whenever practical'' provides an operator substantial discretion in the use of BAST. The statute, on the other hand, requires the use of BAST that DOI determines to be economically feasible on all new drilling and production operations. With respect to existing operations, the Act requires operators to use BAST ''wherever practicable,'' which does not afford the operator complete discretion in the use of systems equipment. In addition, although operators must comply with BSEE regulations, such compliance does not necessarily equate to the use of BAST. Existing paragraph (d) is written in terms of additional measures the Director can require under the Act, and includes a general requirement that the benefits of such measures outweigh the costs.

The proposed rule would more closely track the Act. Proposed § 250.107(c) would provide that wherever failure of equipment may have a significant effect on safety, health, or the environment, an operator must use the BAST that BSEE determines to be economically feasible on all new drilling and production operations, and wherever practicable, on existing operations. Under this proposed provision, BSEE would specify what is economically feasible BAST. This could be accomplished generally, for instance, through the use of NTLs, or on a case-specific basis. To implement the exception allowed by the Act, proposed § 250.107(c)(2) would allow an operator to request an exception from the use of BAST by demonstrating to BSEE that the incremental benefits of using BAST are clearly insufficient to justify the incremental costs of utilizing such technologies.

Service Fees (§ 250.125)

This section would be revised to update the service fee citation to § 250.842 in paragraphs (a)(10) through (a)(15).

Documents Incorporated by Reference (§ 250.198)

This section would be revised to update cross-references to subpart H. The proposed rule would also add by incorporation, ''American Petroleum Institute (API) 570, Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems.''

Tubing and Wellhead Equipment (§ 250.517)

This section would be revised to update the cross-reference to the appropriate subpart H sections from § 250.801 in current regulations to §§ 250.810 through 250.839 in the proposed rule.

Tubing and Wellhead Equipment (§ 250.618)

This section would be revised to update the cross-reference to the appropriate subpart H sections from § 250.801 in current regulations to §§ 250.810 through 250.839 in the proposed rule.

Subpart H—General Requirements

General (§ 250.800)

This section would clarify the design requirements for production safety equipment and specify the appropriate industry standards that must be followed. A provision would be added that would require operators to comply with American Petroleum Institute Recommended Practice (API RP) 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, for all new production systems on fixed leg platforms and floating production systems (FPSs). This section would clarify requirements for operators to comply with the drilling, well completion, well workover, and well production riser standards of API RP 2RD, Recommended Practice for Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs). However, this new section would prohibit the installation of single bore production risers from floating production facilities, effective 1 year from publication of the final rule. The BSEE believes that a single bore production riser does not provide an acceptable level of safety to operate on the OCS when an operator has to perform work through the riser. When an operator performs work through a single bore production riser, wear on the riser may occur that compromises the integrity of the riser. This section would also revise stationkeeping system design requirements for floating production facilities by adding a reference to API RP 2SM, Recommended Practice for Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring, in proposed § 250.800(c)(3).

Safety and Pollution Prevention Equipment (SPPE) Certification (§ 250.801)

Existing § 250.806, pertaining to SPPE certification, would be recodified as proposed § 250.801 and rewritten in plain language. Additional subsections would be added to clarify that SPPE includes SSV and actuators, including those installed on injection wells that are capable of natural flow, and, following a 1-year grace period, boarding shut down valves (BSDVs). The final rule would specify the end date of the grace period. This section would also specify that BSEE would not allow subsurface-controlled subsurface safety valves on subsea wells.

The existing regulations recognize two quality assurance programs: (1) API Spec. Q1 and (2) American National Standards Institute/American Society of Mechanical Engineers (ANSI/ASME) SPPE–1–1994 and SPPE–1d–1996 Addenda. The proposed rule would remove the reference to the ANSI/ASME standards because they are defunct, but would continue to provide that SPPE equipment, which is manufactured and marked pursuant to API Spec. Q1, Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry (ISO TS 29001:2007), would be considered certified SPPE under part 250. The BSEE presumptively considers all other SPPE as noncertified. Notwithstanding this presumption, under proposed § 250.801(c), BSEE may exercise its discretion to accept SPPE manufactured under quality assurance programs other than API Spec. Q1 (ISO TS 29001:2007), provided an operator submits a request to BSEE containing relevant information about the alternative program, and receives BSEE approval under § 250.141.

Requirements for SPPE (§ 250.802)

Existing § 250.806(a)(3), cross-referencing API requirements for SPPE, would be recodified as proposed §§ 250.802(a) and (b).

Proposed § 250.802(c) would include a summary of some of the requirements that are contained in documents that are currently incorporated by reference to provide examples of the types of requirements that are contained in these documents. These requirements would address a range of activities over the entire lifecycle of the equipment that are intended to increase the reliability of the equipment through lifecycle analysis. These include:

- Independent third party review and certification;
- Manufacturing controls;
- Design verification and testing;
- Traceability requirements;
- Installation and testing protocols; and
- Requirements for the use of qualified parts and personnel to perform repairs.

The lifecycle analysis for SPPE would consider the ''cradle-to-grave'' implications of the associated equipment. Lifecycle analysis would also be a tool to evaluate the operational use, maintenance, and repair of SPPE from an equipment lifecycle perspective. Requirements that address the full lifecycle of critical equipment are essential to increase the overall level of certainty that this equipment would perform in emergency situations and would provide documentation from manufacture through the end of the operational limits of the SPPE equipment.

Proposed § 250.802(c)(1) would require that each device be designed to function and to close at the most extreme conditions to which it may be exposed. This includes extreme temperature, pressure, flow rates, and environmental conditions. Under the proposed rule, an operator would be required to have an independent third party review and certify that each device will function as designed under the conditions to which it may be exposed. The independent third party would be required to have sufficient expertise and experience to perform the review and certification.

A table would be added in proposed § 250.802(d) to clarify when operators must install certified SPPE equipment. Under the proposed rule, non-certified SPPE already in service at a well could remain in service, but if the equipment requires offsite repair, re-manufacturing, or any hot work such as welding, it must be replaced with certified SPPE.

Proposed § 250.802(e) would require that operators must retain all documentation related to the manufacture, installation, testing, repair, redress, and performance of SPPE equipment until 1 year after the date of decommissioning of the equipment.

What SPPE failure reporting procedures must I follow? (§ 250.803)

Proposed § 250.803 would establish SPPE failure reporting procedures. Proposed § 250.803(a) would require operators to follow the failure reporting requirements contained in Section 10.20.7.4 of API Spec. 6A for SSVs, BSDVs, and USVs and Section 7.10 of API Spec. 14A and Annex F of API RP 14B for SSSVs, and to provide a written report of equipment failure to the manufacturer of such equipment within 30 days after the discovery and identification of the failure. The proposed rule would define a failure as any condition that prevents the equipment from meeting the functional specification. This is intended to assure that design defects are identified and corrected and to assure that equipment is replaced before it fails.

Proposed § 250.803(b) would require operators to ensure that an investigation and a failure analysis are performed within 60 days of the failure to determine the cause of the failure and that the results and any corrective action are documented. If the investigation and analysis is performed by an entity other than the manufacturer, the proposed rule would require operators to ensure that the manufacturer receives a copy of the analysis report.

Proposed § 250.803(c) would specify that if an equipment manufacturer notifies an operator that it has changed the design of the equipment that failed, or if the operator has changed operating or repair procedures as a result of a failure, then the operator must, within 30 days of such changes, report the design change or modified procedures in writing to BSEE.

Additional Requirements for Subsurface Safety Valves (SSSVs) and Related Equipment Installed in High Pressure High Temperature (HPHT) Environments (§ 250.804)

Existing § 250.807 would be recodified as proposed § 250.804, with no significant revisions proposed.

Hydrogen Sulfide (§ 250.805)

Existing § 250.808, pertaining to production operations in zones known to contain hydrogen sulfide (H_2S) or in zones where the presence of H_2S is unknown, as defined in § 250.490, would be recodified as proposed § 250.805. This section would also clarify that the operator must receive approval through the Deepwater Operations Plan (DWOP) process for production operations in HPHT environments containing H_2S, or in HPHT environments where the presence of H_2S is unknown.

[RESERVED] §§ 250.806—250.809

Surface and Subsurface Safety Systems—Dry Trees

Dry Tree Subsurface Safety Devices—General (§ 250.810)

Existing § 250.801(a) would be recodified as proposed § 250.810, and restructured for clarity. This section would also add the equipment flow coupling above and below to the list of devices associated with subsurface safety devices.

Specifications for Subsurface Safety Valves (SSSVs)—Dry Trees (§ 250.811)

Existing § 250.801(b) would be recodified as proposed § 250.811. This section would also add the equipment flow coupling above and below to the list of devices associated with subsurface safety devices. Section 250.811 would permit BSEE to approve non-certified SSSVs in accordance with the process specified in 250.141 regarding alternative procedures or equipment.

Surface-Controlled SSSVs—Dry Trees (§ 250.812)

Existing § 250.801(c) would be recodified as proposed § 250.812. A change from current regulations would require BSEE approval for locating the surface controls at a remote location. The request and approval to locate surface controls at a remote location would be made in accordance with 250.141, regarding alternative procedures or equipment.

Subsurface-Controlled SSSVs (§ 250.813)

Existing § 250.801(d) would be recodified as proposed § 250.813, and rewritten using plain language.

Design, Installation, and Operation of SSSVs—Dry Trees (§ 250.814)

Existing § 250.801(e) would be recodified as proposed § 250.814. Proposed § 250.814(c) would also add a definition of routine operation similarly to what is found under the definitions section at § 250.601.

Subsurface Safety Devices in Shut-in Wells—Dry Trees (§ 250.815)

Existing § 250.801(f) would be recodified as proposed § 250.815, and rewritten in plain language.

Subsurface Safety Devices in Injection Wells—Dry Trees (§ 250.816)

Existing § 250.801(g) would be recodified as proposed § 250.816, and rewritten in plain language.

Temporary Removal of Subsurface Safety Devices for Routine Operations (§ 250.817)

Existing § 250.801(h) would be recodified as proposed § 250.817. The title of the section would be changed for clarity. In proposed § 250.817(c), the term ''support vessel'' would be added as another option for attendance on a satellite structure.

Additional Safety Equipment—Dry Trees (§ 250.818)

Existing § 250.801(i) would be recodified as proposed § 250.818, with no significant revisions proposed.

Specification for Surface Safety Valves (SSVs) (§ 250.819)

The portion of existing § 250.802(c) related to wellhead SSVs and their actuators would be included in proposed § 250.819. The portion of the existing § 250.802(c) related to underwater safety valves would be placed in proposed § 250.833.

Use of SSVs (§ 250.820)

The portion of existing § 250.802(d) related to SSVs would be included in proposed § 250.820. The portion of the existing § 250.802(d) related to underwater safety valves would be placed in proposed § 250.834.

Emergency Action (§ 250.821)

Existing § 250.801(j) would be recodified as proposed § 250.821. The example of an emergency would be revised to refer to a National Weather Service-named tropical storm or hurricane because not all impending storms constitute emergencies. A requirement would be added that oil and gas wells requiring compression must be shut-in in the event of an emergency unless otherwise approved by the District Manager. This section would also include, from existing § 250.803(b)(4)(ii), the valve closure times for dry tree emergency shutdowns.

[RESERVED] §§ 250.822—250.824

Subsea and Subsurface Safety Systems—Subsea Trees

Subsea Tree Subsurface Safety Devices—General (§ 250.825)

Proposed § 250.825(a) is derived from existing § 250.801(a). This section would provide clarification on subsurface safety devices on subsea trees. Requirements for dry trees subsea safety systems can be found at §§ 250.810 through 250.821. This section would also add the equipment flow coupling above and below to the list of devices associated with subsurface safety devices. Proposed § 250.825(a) would also permit operators to seek BSEE approval to use alternative procedures or equipment in accordance with 250.141 if the subsea safety systems proposed for use vary from the regulatory requirements, including those pertaining to dry subsea safety systems found at §§ 250.810 through 250.821.

Proposed § 250.825(b) would provide that, after installing the subsea tree, but before the rig or installation vessel leaves the area, an operator must test all valves and sensors to ensure that they are operating as designed and meet all the conditions specified in subpart H. Proposed § 250.825(b) would permit an operator to seek BSEE approval of a departure under 250.142 in the event the operator cannot perform these tests.

Specifications for SSSVs—Subsea Trees (§ 250.826)

Proposed § 250.826 would be developed from existing § 250.801(b). The portions of § 250.801(b) pertaining to subsurface-controlled SSSVs for dry tree wells would be moved to proposed § 250.811. Subsurface-controlled SSSVs are not allowed on wells with subsea trees.

Surface-Controlled SSSVs—Subsea Trees (§ 250.827)

This section would be derived from existing § 250.801(c). A change from the existing provision would require BSEE approval for locating the surface controls at a remote location.

Design, Installation, and Operation of SSSVs—Subsea Trees (§ 250.828)

Existing § 250.801(e) would be recodified as proposed § 250.828, with changes made to reflect that this section covers subsea tree installations. One change from existing regulations would establish that a well with a subsea tree must not be open to flow while an SSSV is inoperable. The BSEE would not allow exceptions.

Subsurface Safety Devices in Shut-in Wells—Subsea Trees (§ 250.829)

Existing § 250.801(f) would be recodified as proposed § 250.829. The BSEE would also clarify when a surface-controlled SSSV is considered inoperative. This explanation would be added because the hydraulic control pressure to an individual subsea well may not be able to be isolated due to the complexity of the subsea hydraulic distribution of subsea fields.

Subsurface Safety Devices in Injection Wells—Subsea Trees (§ 250.830)

This section would be derived from existing § 250.801(g). The substance of proposed § 250.830 for subsea tree wells would be substantially similar to the regulatory sections pertaining to proposed § 250.816 for dry tree wells. This is one example in which BSEE has consolidated similar provisions for easier public understanding.

Alteration or Disconnection of Subsea Pipeline or Umbilical (§ 250.831)

This is a new section that would be added to codify policy and guidance from an existing BSEE Gulf of Mexico Region NTL, ''Using Alternate Compliance in Safety Systems for Subsea Production Operations,'' NTL No. 2009–G36. The proposed provision would provide that if a necessary alteration or disconnection of the pipeline or umbilical of any subsea well would affect an operator's ability to monitor casing pressure or to test any subsea valves or equipment, the operator must contact the appropriate BSEE District Office at least 48 hours in advance and submit a repair or replacement plan to conduct the required monitoring and testing.

Additional Safety Equipment—Subsea Trees (§ 250.832)

This section would be derived from existing § 250.801(i), with changes made to reflect that this section covers subsea tree installations. The last sentence of existing § 250.801(i), generally requiring closure of surface-controlled SSSVs in certain circumstances, would not be needed for wells with subsea trees, because more specific surface-controlled SSSV closure requirements would be established in proposed §§ 250.838 and 250.839, described later.

Specification for Underwater Safety Valves (USVs) (§ 250.833)

Proposed § 250.833 derives in part from existing § 250.802(c) with references to surface safety valves removed to separate out requirements for the use of dry or subsea trees. The portions of the existing rule concerning surface safety valves for dry trees would be contained in proposed § 250.819. Proposed § 250.833 would also clarify the designations of the primary USV (USV1), the secondary USV (USV2), and that an alternate isolation valve (AIV) may qualify as a USV. Proposed § 250.833(a) would require that operators must install at least one USV on a subsea tree and designate it as the primary USV, and that BSEE must be kept informed if the primary USV designation changes.

Much of the material included in proposed §§ 250.833 through 250.839 derives from existing NTL No. 2009–G36, and is currently implemented through the DWOP process described under §§ 250.286 through 250.295. Inclusion of this material in subpart H would better inform the regulated community of BSEE's expectations, and seeking public comment through this rulemaking will allow for possible improvements.

Use of USVs (§ 250.834)

Proposed § 250.834, pertaining to the inspection, installation, maintenance, and testing of USVs, derives from existing § 250.802(d) with references to surface safety valves removed to separate out requirements for the use of dry or subsea trees. This section would add references to USVs designated as primary, secondary, and any alternate isolation valve (AIV) that acts as a USV and also would add a reference to DWOPs.

Specification for All Boarding Shut Down Valves (BSDVs) Associated With Subsea Systems (§ 250.835)

Proposed § 250.835 would be a new section which would establish minimum design and other requirements for BSDVs and their actuators. This section would impose the requirements for the use of a BSDV, which assumes the role of the SSV required by 30 CFR Part 250, Subpart H for a traditional dry tree. This would ensure the maximum level of safety for the production facility and the people aboard the facility. Because the BSDV is the most critical component of the subsea system, it is necessary that this valve be subject to rigorous design and testing criteria.

Use of BSDVs (§ 250.836)

Proposed § 250.836 would establish a new requirement that all BSDVs must be inspected, maintained, and tested according to the provisions of API RP 14H. This section also specifies what the operator would do if a BSDV does not operate properly or if fluid flow is observed during the leakage test.

Emergency Action and Safety System Shutdown (§ 250.837)

Proposed § 250.837 would replace existing § 250.801(j) for subsea tree installations. New requirements would be added to clarify allowances for valve closing sequences for subsea installations and specify actions required for certain situations. Proposed § 250.837(c) and (d) would describe a number of emergency situations requiring that shutdowns occur and safety valves be closed, and in certain situations that hydraulic systems be bled.

What are the Maximum Allowable Valve Closure Times and Hydraulic Bleeding Requirements for an Electro-hydraulic Control System? (§ 250.838)

Proposed § 250.838 would establish maximum allowable valve closure times and hydraulic system bleeding requirements for electro-hydraulic control systems. Proposed paragraph (b) would apply to electro-hydraulic control systems when an operator has not lost communication with its rig or platform. Proposed paragraph (c) would apply to electro-hydraulic control systems when an operator has lost communication with its rig or platform. Each paragraph would include a table containing valve closure times for BSDVs, USVs, and surface-controlled SSSVs under the various scenarios described in proposed § 250.837(c). The tables derive from Appendices to NTL No. 2009–G36.

What are the maximum allowable valve closure times and hydraulic bleeding requirements for direct-hydraulic control system? (§ 250.839)

Proposed § 250.839 would establish maximum allowable valve closure times and hydraulic system bleeding requirements for direct-hydraulic control systems. It would contain a valve closure table comparable to those contained in proposed § 250.838.

Production Safety Systems

Design, Installation, and Maintenance—General (§ 250.840)

Existing § 250.802(a) would be recodified as proposed § 250.840. Several new production components (pumps, heat exchangers, etc.) would be added to this section.

Platforms (§ 250.841)

Existing § 250.802(b) would be recodified as proposed § 250.841. New requirements for facility process piping would be added in proposed § 250.841(b). The new paragraph would require adherence to existing industry documents, API RP 14E, Design and Installation of Offshore Production Platform Piping Systems and API 570, Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems. Both of these documents would be incorporated by reference in § 250.198. The proposed rule would also specify that the BSEE District Manager could approve temporary repairs to facility piping on a case-by-case basis for a period not to exceed 30 days.

Approval of Safety Systems Design and Installation Features (§ 250.842)

Existing § 250.802(e) would be recodified as proposed § 250.842, including the service fee associated with the submittal of the production safety system application. The proposed rule would require adherence to API Recommended Practice documents pertaining to the design of electrical installations. The proposed rule would also require completion of a hazard analysis during the design process and require that a hazards analysis program be in place to assess potential hazards during the operation of the platform. A table would be placed in the proposed rule for clarity, amplifying some of the current requirements. This section would also add the requirements that the designs for the mechanical and electrical systems were reviewed, approved, and stamped by a registered professional engineer. Also, it would add a requirement that the as-built piping and instrumentation diagrams

(P&IDs) must be certified correct and stamped by a registered professional engineer. This section would also specify that the registered professional engineer, in both instances, must be registered in a State or Territory of the United States and have sufficient expertise and experience to perform the duties. The importance of these new provisions were highlighted in the Atlantis investigation report ''BP'S Atlantis Oil And Gas Production Platform: An Investigation of Allegations that Operations Personnel Did Not Have Access to Engineer-Approved Drawings,'' published March 4, 2011, prepared by BSEE's predecessor agency, the Bureau of Ocean Energy Management, Regulation and Enforcement. A copy of this report is available online at the following address: *http://www.bsee.gov/uploadedFiles/03-0311%20BOEMRE%20Atlantis%20Report%20-%20FINAL.pdf.* To clarify some of the issues discussed in the Atlantis investigation report related to as-built P&IDs and to clarify other diagram requirements, proposed § 250.842 would require the following:

- Engineering documents to be stamped by a registered professional engineer;
- Operators to certify that all listed diagrams, including P&IDs are correct and accessible to BSEE upon request; and
- All as-built diagrams outlined in § 250.842(a)(1) and (2) to be submitted to the District Managers.

The proposed § 250.842(b)(3) would impose a requirement that the operator certify in its application that it has performed a hazard analysis during the design process in accordance with API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, and that it has a hazards analysis program in place to assess potential hazards during the operation of the platform. Although the regulations pertaining to an operator's safety and environmental management systems (SEMS) program already require a hazards analysis under § 250.1911, the hazards analysis for the production platform required under the proposed rule would contain more detail under the incorporated API Recommended Practice than is currently required under the SEMS regulation.

The operator must comply with both hazards analysis requirements from each respective subpart; however, these requirements for subpart H may also be used to satisfy a portion of the hazards analysis requirements in subpart S.

[RESERVED] §§ 250.843–250.849

Additional Production System Requirements

Production System Requirements—General (§ 250.850)

The proposed rule would split existing § 250.803 into a number of sections (proposed §§ 250.850 through 250.872) to make the regulations shorter, and thus more readable. Existing § 250.803(a) would be codified as proposed § 250.850.

Pressure Vessels (Including Heat Exchangers) and Fired Vessels (§ 250.851)

Existing § 250.803(b)(1), establishing requirements for pressure and fired vessels, would be codified as proposed § 250.851. Tables would be placed in the proposed rule for clarity.

Flowlines/Headers (§ 250.852)

Existing § 250.803(b)(2), which establishes requirements for flowlines and headers, would be codified as proposed § 250.852. The existing regulations require the establishment of new operating pressure ranges at any time a ''significant'' change in operating pressures occurs. The proposed rule would specify instead that new operating pressure ranges of flowlines would be required at any time when the normalized system pressure changes by 50 psig (pounds per square inch gauge) or 5 percent, whichever is higher. New requirements also would be added for wells that flow directly to a pipeline without prior separation and for the closing of SSVs by safety sensors. A table would be placed in the proposed rule for clarity.

Safety Sensors (§ 250.853)

Existing § 250.803(b)(3), pertaining to safety sensors, would be codified as proposed § 250.853 with the addition that all level sensors would have to be equipped to permit testing through an external bridle on new vessel installations.

Floating Production Units Equipped With Turrets and Turret Mounted Systems (§ 250.854)

Proposed § 250.854 would contain a new requirement for floating production units equipped with turrets and turret mounted systems. The operator would have to integrate the auto slew system with the safety system allowing for automatic shut-in of the production process including the sources (subsea wells, subsea pumps, etc.) and releasing of the buoy. The safety system would be required to immediately initiate a process system shut-in according to §§ 250.838 and 250.839 and release the buoy to prevent hydrocarbon discharge and damage to the subsea infrastructure when the buoy is clamped, the auto slew mode is activated, and there is a ship heading/position failure or an exceedance of the rotational tolerances of the clamped buoy.

This new section would also require floating production units equipped with swivel stack arrangements, to be equipped with a leak detection system for the portion of the swivel stack containing hydrocarbons. The leak detection system would be required to be tied into the production process surface safety system allowing for automatic shut-in of the system. Upon seal system failure and detection of a hydrocarbon leak, the surface safety system would be required to immediately initiate a process system shut-in according to §§ 250.838 and 250.839. These new requirements are needed because they are not addressed in the currently incorporated API RP 14C and would help protect against hydrocarbon discharge in the event of failures.

Emergency Shutdown (ESD) System (§ 250.855)

Existing § 250.803(b)(4), pertaining to emergency shutdown systems, would be recodified as proposed § 250.855. The existing regulation provides that only ESD stations at a boat landing may utilize a loop of breakable synthetic tubing in lieu of a valve. The proposed rule would clarify that the breakable loop in the ESD system is not required to be physically located on the boat landing; however, in all instances it must be accessible from a boat.

Engines (§ 250.856)

Existing § 250.803(b)(5), pertaining to engine exhaust and diesel engine air intake, would be recodified as proposed § 250.856. A listing of diesel engines that do not require a shutdown device would be added to the proposed rule for clarification.

Glycol Dehydration Units (§ 250.857)

Existing § 250.803(b)(6), pertaining to glycol dehydration units, would be recodified as proposed § 250.857. New requirements for flow safety valves and shut down valves on the glycol dehydration unit would be added to the proposed rule.

Gas Compressors (§ 250.858)

Existing § 250.803(b)(7), pertaining to gas compressors, would be recodified as proposed § 250.858. New proposed requirements would be added to require the use of pressure recording devices to establish any new operating pressure range changes greater than 5 percent or 50 psig, whichever is higher. For pressure sensors on vapor recovery units, proposed § 250.858(c) would provide that when the suction side of the compressor is operating below 5 psig and the system is capable of being vented to atmosphere, an operator is not required to install PSH and PSL sensors on the suction side of the compressor.

Firefighting Systems (§ 250.859)

Existing § 250.803(b)(8), pertaining to firefighting systems, would be recodified in proposed §§ 250.859, 250.860, and 250.861 and expanded. A number of the proposed additional features were included in an earlier NTL No. 2006–G04, ''Fire Prevention and Control Systems,'' and are necessary to update the agency regulations pertaining to firefighting.

Proposed § 250.859(a)(2) would include additional requirements. Existing § 250.803(b)(8)(i) and (ii) would be included in proposed § 250.859(a)(1) and (2). This paragraph would specify that within 1 year after the publication date of a final rule, operators must equip all new firewater pump drivers with automatic starting capabilities upon activation of the ESD, fusible loop, or other fire detection system. For electric driven firewater pump drivers, in the event of a loss of primary power, operators would be required to install an automatic transfer switch to cross over to an emergency power source in order to maintain at least 30 minutes of run time. The emergency power source would have to be reliable and have adequate capacity to carry the locked-rotor currents of the fire pump motor and accessory equipment. Operators would be required to route power cables or conduits with wires installed between the fire water pump drivers and the automatic transfer switch away from hazardous-classified locations that can cause flame impingement. Power cables or conduits with wires that connect to the fire water pump drivers would have to be capable of maintaining circuit integrity for not less than 30 minutes of flame impingement.

Proposed § 250.859(a)(5) would require that all firefighting equipment located on a facility be in good working order. Existing § 250.803(b)(8)(iv) and (v) would be included in proposed § 250.859(a)(3) and (4).

Proposed § 250.859(b) would address inoperable firewater systems. It would specify that if an operator is required to maintain a firewater system and it becomes inoperable, the operator either must shut-in its production operations while making the necessary repairs, or request that the appropriate BSEE District Manager grant a departure under § 250.142 to use a firefighting system using chemicals on a temporary basis for a period up to 7 days while the necessary repairs occur. It would provide further that if the operator is unable to complete repairs during the approved time period because of circumstances beyond its control, the BSEE District Manager may grant extensions to the approved departure for periods up to 7 days.

Chemical Firefighting System (§ 250.860)

Existing § 250.803(b)(8)(iii) allows the use of a chemical firefighting system in lieu of a water-based system if the District Manager determines that the use of a chemical system provides equivalent fire-protection control. A number of the additional details were included from NTL 2006–G04, and are necessary to update the agency's regulations pertaining to firefighting. This proposed section would specify requirements regarding the use of chemical-only systems on major platforms, minor manned platforms, or minor unmanned platforms. The proposed rule would define the terms of major and manned platforms. It would also require a determination by the BSEE District Manager that the use of a chemical-only system would not increase the risk to human safety.

To provide a basis for the District Manager's determination that the use of a chemical system provides equivalent fire-protection control, the proposed rule would require an operator to submit a justification addressing the elements of fire prevention, fire protection, fire control, and firefighting on the platform. As a further basis, the operator would need to submit a risk assessment demonstrating that a chemical-only system would not increase the risk to human safety. The rule would contain a table listing the items that must be included in the risk assessment.

We are currently considering applying the proposed requirements, for approval of chemical-only firefighting systems, to major and manned minor platforms that already have agency approval, as well as to new platforms. We solicit comments as to whether including already-approved platforms would be feasible and would provide an additional level of safety and protection so as to justify the cost and effort.

Proposed § 250.860(b) would address what an operator must maintain or submit for the chemical firefighting system. This section would also clarify that once the District Manager approves the use of a chemical-only fire suppressant system, if the operator intends to make any significant change to the platform such as placing a storage vessel with a capacity of 100 barrels or more on the facility, adding production equipment, or planning to man an unmanned platform, it must seek BSEE District Manager approval.

Proposed § 250.860(c) would address the use of chemical-only firefighting systems on platforms that are both minor and unmanned. The rule would authorize the use of a U.S. Coast Guard type and size rating ''B–II'' portable dry chemical unit (with a minimum UL Rating (US) of 60–B:C) or a 30-pound portable dry chemical unit, in lieu of a water system, on all platforms that are both minor and unmanned, as long as the operator ensures that the unit is available on the platform when personnel are on board. A facility-specific authorization would not be required.

Foam Firefighting System (§ 250.861)

Proposed § 250.861 would establish requirements for the use of foam firefighting systems. Under the proposed rule, when foam firefighting systems are installed as part of a firefighting system, the operator would be required annually to (1) conduct an inspection of the foam concentrates and their tanks or storage containers for evidence of excessive sludging or deterioration; and (2) send tested samples of the foam concentrate to the manufacturer or authorized representative for quality condition testing and certification. The rule would specify that the certification document must be readily accessible for field inspection. In lieu of sampling and certification, the proposed rule would allow operators to replace the total inventory of foam with suitable new stock. The rule would also require that the quantity of concentrate must meet design requirements, and tanks or containers must be kept full with space allowed for expansion.

Fire and Gas-Detection Systems (§ 250.862)

Existing § 250.803(b)(9), pertaining to fire and gas-detection systems, would be recodified as proposed § 250.862.

Electrical Equipment (§ 250.863)

Existing § 250.803(b)(10) pertaining to electrical equipment, would be recodified as proposed § 250.863.

Erosion (§ 250.864)

Existing § 250.803(b)(11) pertaining to erosion control, would be recodified as proposed § 250.864.

Surface Pumps (§ 250.865)

Proposed § 250.865, pertaining to surface pumps, would contain material from existing § 250.803(b)(1)(iii), pressure and fired vessels, as well as new requirements for pump installations. This would include a requirement to use pressure recording devices to establish new operating pressure ranges for pump discharge sensors, and a specific requirement to equip all pump installations with the protective equipment recommended by API RP 14C, Appendix A—A.7, Pumps.

Personnel Safety Equipment (§ 250.866)

Proposed § 250.866 is a new section that would require that all personnel safety equipment be maintained in good working order.

Temporary Quarters and Temporary Equipment (§ 250.867)

Proposed § 250.867 is a new section that would require that all temporary quarters installed on OCS facilities be approved by BSEE and that temporary quarters be equipped with all safety devices required by API RP 14C, Appendix C. It would also clarify that the District Manager could require the installation of a temporary firewater system. This new section would also require that temporary equipment used for well testing and/or well clean-up would have to be approved by the District Manager.

The temporary equipment requirements are needed based on a number of incidents involving the unsuccessful use of such equipment. Currently, BSEE receives limited information regarding temporary equipment. These changes would help ensure that BSEE has a more complete understanding of all operations associated with temporary quarters and temporary equipment.

Non-metallic Piping (§ 250.868)

Proposed § 250.868 is a new section that would require that non-metallic piping be used only in atmospheric, primarily non-hydrocarbon service such as piping in galleys and living quarters, open atmospheric drain systems, overboard water piping for atmospheric produced water systems, and firewater system piping.

General Platform Operations (§ 250.869)

Existing § 250.803(c), pertaining to general platform operations, would be codified as proposed § 250.869, with a new requirement in the proposed rule (§ 250.869(e)) that would prohibit utilization of the same sensing points for both process control devices and component safety devices on new installations. This section would also establish monitoring procedures for bypassed safety devices and support systems.

A new provision in paragraph (2)(i) would require the computer-based technology system control stations to not only show the status of, but be capable of displaying, operating conditions. It also clarifies that if the electronic systems are not capable of displaying operating conditions, then industry would have to have field personnel monitor the level and pressure gauges and be in communication with the field personnel.

A new provision, proposed § 250.869(a)(3), would be added that would specify that operators must not bypass, for maintenance or startup, any element of the emergency support system (ESS) or other support system required by API RP 14C, Appendix C, without first receiving approval from BSEE to use alternative procedures or equipment in accordance with 250.141. These are essential systems that provide a level of protection to a facility by initiating shut-in functions or reacting to minimize the consequences of released hydrocarbons. The rule would contain a non-exclusive list of these systems.

Time Delays on Pressure Safety Low (PSL) Sensors (§ 250.870)

Proposed § 250.870, another new provision, would be added to incorporate guidance of existing NTL 2009–G36, related to time delays on PSL sensors. The proposed rule would specify that operators must apply industry standard Class B, Class C, and Class B/C logic to all applicable PSL sensors installed on process equipment, as long as the time delay does not exceed 45 seconds. Use of a PSL sensor with a time delay greater than 45 seconds would require BSEE approval of a request under § 250.141. Operators would be required to document on their field test records any use of a PSL sensor with a time delay greater than 45 seconds.

For purposes of proposed § 250.870, PSL sensors would be categorized as follows:

Class B safety devices have logic that allows for the PSL sensors to be bypassed for a fixed time period (typically less than 15 seconds, but not more than 45 seconds). These sensors are mostly used in conjunction with the design of pump and compressor panels and include PSL sensors, lubricator no-flows, and high-water jacket temperature shutdowns.

Class C safety devices have logic that allows for the PSL sensors to be bypassed until the component comes into full service (*i.e.,* at the time at which the startup pressure equals or exceeds the set pressure of the PSL sensor, the system reaches a stabilized pressure, and the PSL sensor clears).

Class B/C safety devices have logic that allows for the PSL sensors to incorporate a combination of Class B and Class C circuitry. These devices are used to ensure that the PSL sensors are not unnecessarily bypassed during startup and idle operations, such as, Class B/C bypass circuitry activates when a pump is shut down during normal operations. The PSL sensor remains bypassed until the pump's start circuitry is activated and either the Class B timer expires no later than 45 seconds from start activation or the Class C bypass is initiated until the pump builds up pressure above the PSL sensor set point and the PSL sensor comes into full service.

The proposed rule would also provide that if an operator does not install time delay circuitry that bypasses activation of PSL sensor shutdown logic for a specified time period on process and product transport equipment during startup and idle operations, the operator must manually bypass (pin out or disengage) the PSL sensor, with a time delay not to exceed 45 seconds. Use of a manual bypass that involves a time delay greater than 45 seconds would require approval of a request made under § 250.141 from the appropriate BSEE District Manager.

Welding and Burning Practices and Procedures (§ 250.871)

Existing § 250.803(d), pertaining to welding and burning practices and procedures, would be recodified as proposed § 250.871, with a proposed new requirement that would prohibit variance from the approved welding and burning practices and procedures unless such variance were approved by BSEE as an acceptable alternative procedure or equipment in accordance with § 250.141.

Atmospheric Vessels (§ 250.872)

Proposed § 250.872 is a new section that would require atmospheric vessels used to process and/or store liquid hydrocarbons or other Class I liquids as described in API RP 500 or 505 to be equipped with protective equipment identified in API RP 14C. Requirements for level safety high sensors (LSHs) would also be added. There would also be clarification added that for atmospheric vessels that have oil buckets, the LSH sensor would have to be installed to sense the level in the oil bucket.

Subsea Gas Lift Requirements (§ 250.873)

This is a new section that would be added to codify existing policy and guidance from the DWOP process. The BSEE has approved the use of gas lift equipment and methodology in subsea wells, pipelines, and risers via the DWOP approval process and imposed conditions to ensure that the necessary safety mitigations are in place. While the basic requirements of API RP 14C still apply for surface applications, certain clarifications need to be made to ensure regulatory compliance when gas lift for recovery for subsea production operations is used. Proposed § 250.873 would add the following new requirements: design of the gas lift supply pipeline according to API 14C; installation of specific safety valves, including a gas-lift shutdown valve and a gas-lift isolation valve; outlining the valve closure times and hydraulic bleed requirements according to the DWOP; and gas lift valve testing requirements.

Subsea Water Injection Systems (§ 250.874)

This is a new section that would be added to codify existing policy and guidance from the DWOP process, related to water flood injection via subsea wellheads. This is similar to the subsea gas lift as discussed in the previous section. The basic requirements of API RP 14C still apply for surface applications, yet certain clarifications need to be made to ensure regulatory compliance for the use of water flood systems for recovery for subsea production operations. Proposed § 250.874 would add the following new requirements: adhere to the water injection requirements described in API RP 14C for the water injection equipment located on the platform; equip the water injection system with certain safety valves, including water injection valve (WIV) and a water injection shutdown valve (WISDV); establish the valve closure times and hydraulic bleed requirements according to the DWOP; and establish WIV testing requirements.

Subsea Pump Systems (§ 250.875)

This is a new section that would be added to codify policy and guidance from an existing National NTL, ''Subsea Pumping for Production Operations,'' NTL No. 2011–N11 and the DWOP. Proposed § 250.875 would outline subsea pump system requirements, including: the installation and location of specific safety valves, operational considerations under circumstances if the maximum possible discharge pressure of the subsea pump operating in a dead head situation could be greater than the maximum allowable operating pressure (MAOP) of the pipeline, the reference to desired valve closure times contained within the DWOP, and subsea pump testing.

Fired and Exhaust Heated Components (§ 250.876)

This is a new section that would require certain tube-type heaters to be removed, inspected, repaired, or replaced every 5 years by a qualified third party. This new section would also add that the inspection results must be documented, retained for at least 5 years, and made available to BSEE upon request. This new section was added in part due to the BSEE investigation report into the Vermillion 380 platform fire ''Vermilion Block, Production Platform A: An Investigation of the September 2, 2010 Incident in the Gulf of Mexico, May 23, 2011.'' The report states that ''The immediate cause of the fire was that the Heater-Treater's weakened fire tube became malleable and collapsed in a 'canoeing' configuration, ripping its steel apart and creating openings through which hydrocarbons escaped, came into contact with the Heater-Treater's hot burner, and then produced flames.'' The report states that a possible contributing cause of the fire was a lack of routine inspections of the fire tube. From the report, ''we found that a possible contributing cause of the fire was the company's failure to follow the [BSEE] regulations related to API 510 that require an inspection plan for Heater-Treaters and its failure to regularly inspect and maintain the Heater-Treater. [BSEE] regulations require the operator to routinely maintain and inspect the pressure vessel. While the regulations do not specifically address the fire tube inside of the Heater-Treater, weaknesses in the fire tube and temperature-related issued would likely have been identified if the operator routinely inspected the Heater-Treater.''

The Vermillion 380 platform fire is one of the recently documented incidents involving fires or hazards caused by fire tube failures. Since 2011, there have been other similar incidents involving tube-type heaters. These types of incidents involving tube-type heaters are a concern for BSEE due to the potential safety issues of offshore personnel and infrastructure. The BSEE determined that this new requirement would help ensure tube-type heaters are inspected routinely to minimize the risk of tube-type heater incidents.

[RESERVED] §§ 250.877–250.879

Safety Device Testing

Production Safety System Testing (§ 250.880)

Existing § 250.804(a), pertaining to production safety system testing, would be recodified as proposed § 250.880. A table would be inserted to help to clarify requirements and make them easier to find.

Proposed § 250.880(a) would include the notification requirement from existing § 250.804(a)(12) and would clarify that an operator must give BSEE 72 hours notice prior to commencing production so that BSEE may witness a preproduction test and conduct a preproduction inspection of the integrated safety system.

In proposed § 250.880, BSEE would revise existing requirements to increase certain liquid leakage rates from 200 cubic centimeters per minute to 400 cubic centimeters per minute and gas leakage rates from 5 cubic feet per minute to 15 cubic feet per minute. These proposed changes reflect consistency with industry standards and account for accessibility of equipment in deepwater/subsea applications. In 1999, the former Minerals Management Service funded the Technology Assessment and Research Project #272, ''Allowable Leakage Rates and Reliability of Safety and Pollution Prevention Equipment'', to review increased leakage rates for safety and pollution prevention equipment. The recommendations section of this study states, ''there appears to be preliminary evidence indicating that more stringent leakage requirements specified in 30 CFR Part 250 may not significantly increase the level of safety when compared to the leakage rates recommended by API. However, a complete hazards analysis should be conducted, and industry safety experts should be consulted.'' You may view the complete report at *http://bsee.gov/Research-and-Training/Technology-Assessment-and-Research/Project-272.aspx.* In the past, BSEE has allowed a higher leakage rate than that prescribed in existing § 250.804 as an approved alternate compliance measure in the DWOP because of BSEE's and industry's acceptance of the ''barrier concept''. The barrier concept moves the SSV from the well to the BSDV that has been proven to be as safe as, or safer than, what is required by the current regulations.

The following table compares existing allowable leakage rates to the proposed increased allowable leakage rates for various safety devices:

Item name	Allowable leakage rate testing requirements under current regulations	The increased allowable leakage rate testing requirements for the proposed rule
Surface-controlled SSSVs (including devices installed in shut-in and injection wells).	liquid leakage rate < 200 cubic centimeters per minute, or.	liquid leakage rate < 400 cubic centimeters per minute, or
	gas leakage rate < 5 cubic feet per minute	gas leakage rate < 15 cubic feet per minute.
Tubing plug	liquid leakage rate < 200 cubic centimeters per minute, or.	liquid leakage rate < 400 cubic centimeters per minute, or
	gas leakage rate < 5 cubic feet per minute	gas leakage rate < 15 cubic feet per minute.
Injection valves	liquid leakage rate < 200 cubic centimeters per minute, or.	liquid leakage rate < 400 cubic centimeters per minute, or
	gas leakage rate < 5 cubic feet per minute	gas leakage rate < 15 cubic feet per minute.
USVs	0 leakage rate	liquid leakage rate < 400 cubic centimeters per minute, or
		gas leakage rate < 15 cubic feet per minute.
Flow safety valves (FSV)	liquid leakage rate < 200 cubic centimeters per minute, or.	liquid leakage rate < 400 cubic centimeters per minute, or
	gas leakage rate < 5 cubic feet per minute	gas leakage rate < 15 cubic feet per minute.

Additionally, proposed § 250.880 would contain new requirements for BSDVs, changes to the testing frequency for underwater safety valves, and requirements for the testing of ESD systems, as well as pneumatic/electronic switch LSH and level safety low (LSL) controls. This section would also add testing and repair/replacement requirements for subsurface safety devices and associated systems on subsea trees and for subsea wells shut-in and disconnected from monitoring capability for greater than 6 months. Many of these requirements would be included in a series of proposed tables.

[RESERVED] (§§ 250.881–250.889)

Records and Training

Records (§ 250.890)

Existing § 250.804(b), pertaining to maintaining records of installed safety devices, would be recodified as proposed § 250.890, with new information submittal requirements that are meant to assist BSEE in contacting operators.

Safety Device Training (§ 250.891)

Existing § 250.805, pertaining to personnel training, would be recodified as proposed § 250.891. The wording of this section would be changed to more accurately capture the scope of subpart S training requirements.

[RESERVED] (§§ 250.892–250.899)

Additional Comments Solicited

In additional to the input requested above, BSEE requests public comment on the following:

Organization of Rule Based on Use of Subsea Trees and Dry Trees

The BSEE requests general public comments on whether the proposed reorganization of the regulations by type of facility (subsea tree and dry tree) is helpful.

Lifecycle Analysis Approach to Other Types of Critical Equipment Such as Blowout Preventers (BOPs)

The BSEE is considering applying a lifecycle analysis approach to other types of critical equipment that we regulate. We are specifically requesting comments on how this approach could be used to assist in increasing the reliability of critical equipment such as BOPs. The BSEE currently relies on pressure testing to demonstrate BOP performance and reliability. Can a lifecycle approach replace or supplement these requirements? Are there other types of critical equipment that are good candidates for the life cycle approach? Are there industry standards that can serve as the basis for BSEE's increased focus on the life cycle of critical equipment?

Failure Reporting and Information Dissemination

Industry standards such as API Spec. 14A include processes and procedures for addressing the reporting and subsequent review of the failure of critical equipment. This information is extremely important in ensuring continuous improvement in the design and reliability of the equipment. Based on recent experiences in the GOM and input from industry, BSEE believes there are a variety of factors that discourage the timely and voluntary exchange of this type of information with the rest of the industry and BSEE. The BSEE believes that a more comprehensive and formalized reporting and review system would increase the exchange of data and allow the industry and BSEE to identify trends and issues that impact offshore safety. The BSEE requests comments on whether these failure reports should be submitted directly to BSEE or provided to an appropriate third party organization that would be responsible for reviewing and analyzing the data and notifying the industry of potential problems. The BSEE also requests comments on how this type of system could be broaden to include international offshore operations.

Third Party Certification Organizations

In various sections of the regulations, BSEE requires third party verification of the design of systems and equipment. The design, installation, inspection, maintenance, and repair of subsea equipment and systems presents a variety of unique technical challenges to the industry and BSEE. The BSEE solicits comments on the use of third party certification organizations to assist BSEE in ensuring that these systems are designed and maintained during its entire service life with an acceptable degree of risk. The BSEE also solicits comments on the use of a single lifecycle certification program that covers SPPE, risers, platforms, and production systems.

Information Requested on Opportunities To Limit Emissions of Natural Gas From OCS Production Equipment

Throughout the production process, certain volumes of natural gas are lost to the atmosphere through fugitive emissions and flaring or venting. The BSEE is evaluating opportunities to reduce methane and other air emissions through use of the best available production equipment technology and practices. We are seeking additional information on these opportunities. Information obtained through public comments on this topic may be used to support a Regulatory Impact Analysis.

We are not proposing new production equipment requirements to limit emissions in this rulemaking, but are seeking additional information on technologies and costs for emissions-limiting equipment that can be used on OCS production facilities. This information will be considered consistent with applicable statutes and E.O. 12866/13563 during BSEE's evaluation of future regulatory options.

The GAO issued a report on this topic in October 2010: *http://www.gao.gov/new.items/d1134.pdf, Opportunities Exist To Capture Vented and Flared Natural Gas, Which Would Increase Royalty Payments and Reduce Greenhouse Gases.* As part of Interior's response to that report, BSEE is further evaluating opportunities to limit natural gas emissions on existing production facilities.

Venting, flaring, and small fugitive releases of natural gas are often a necessary part of production; however, the lost gas has safety, economic, and environmental implications. It represents a loss of revenue for lessees, loss of royalty revenue for the Federal government, and adds to greenhouse gases in the atmosphere. Implementation of available emissions-limiting equipment and venting and flaring reduction technologies could increase sales volumes, revenue, and improve the environment.

Routine preventive maintenance and certain technologies are applied to capture or flare much of this lost gas. The technologies' feasibility varies and heavily depends on the characteristics of the OCS production facility. The following emissions-limiting equipment may provide for prevention, capture, or flaring of released natural gas:

(1) Gas dehydration: A flash tank separator and vapor recovery unit that reduces the amount of gas that is vented into the atmosphere.

(2) Pneumatic devices: Replacing pneumatic devices at all stages of production that release, or ''bleed,'' gas at a high rate (high-bleed pneumatics) with devices that bleed gas at a lower rate (low-bleed pneumatics), or installing an air pneumatic system and converting to instrument air instead.

(3) Losses from flashing (reciprocating compressors): Replace cup ring, cups, and cases. How often is this preventive maintenance performed on reciprocating compressors?

(4) Losses from flashing (centrifugal compressors): Replace wet seals with dry seals or install a gas recovery system.

We are seeking additional information on the cost, economic viability and estimated effectiveness of equipment and these actions or others on OCS production facilities. If your OCS production facilities already employ the best available emissions limiting technology and equipment, or if there are other equipment or practices that limit emissions on OCS production facilities, we welcome that information also. Does your company have a leak detection (infrared/acoustic detection equipment) or maintenance program for OCS production facilities? What has your company found regarding the cost-effectiveness and benefits of such a program? Comments from the public are also welcome.

Flaring

We are seeking additional information similar to that provided by the Offshore Operators Committee (OOC) at the then Bureau of Ocean Energy Management Regulation and Enforcement, March 2011, workshop on venting and flaring. The profiles of operator's production facilities vary widely and BSEE welcomes additional facility information from operators beyond that provided at the workshop.

The workshop (75 FR 81950) regulations.gov docket BOEM–2010–0042 resulted in some information for the installation of flare equipment on GOM shelf facilities. The cost information in the following table was provided by OOC for a single operator's GOM production facilities. Furthermore we would like to get similar information from other operators. We are specifically seeking your company count of the facility types listed in the table below, and if the associated estimated cost for each facility type is appropriate.

Facility type	Estimated cost for flare installation
Gas already flared	$0
Satellite facilities with no significant venting	0
Facilities with adequate vent boom to support flare	1,629,000
Facilities with inadequate vent boom, but structure can support flare boom installation	2,639,000
Facilities with inadequate vent boom, structure cannot support flare boom installation.	6,664,000

Procedural Matters

Regulatory Planning and Review (Executive Orders 12866 and 13563)

Executive Order 12866 provides that the Office of Information and Regulatory Affairs (OIRA) will review all significant rules. The OIRA determined that that this rule is not a significant rulemaking under E.O. 12866. Nevertheless, BSEE had an outside contractor prepare an economic analysis to assess the anticipated costs and potential benefits of the proposed rulemaking. The following discussions summarize the economic analysis; however, a complete copy of the economic analysis can be viewed at *www.Regulations.gov* (use the keyword/ID ''BSEE–2012–0005'').

This proposed rule largely codifies standard industry practice and clarifies existing BSEE regulations and guidance. The requirements under the proposed rule align with those under the 1988 rule and other existing documents that regulate and guide the industry (e.g., Deepwater Operations Plans (DWOPs), Notices to Lessees (NTLs), and American Petroleum Institute (API) industry standards). The economic effect of the proposed rule is confined to certain reporting, certification, inspection, and documentation requirements, which have an estimated incremental cost for offshore oil and natural gas production facilities in aggregate of approximately $170,000 per year (see Table 1 below) without taking into consideration the potential benefits associated with the potential reduction in oil spills and injuries. The following Table provides a summary of the economic analysis.

TABLE 1—ECONOMIC ANALYSIS SUMMARY

$ costs of proposed rule =	−($1.71 million).
Potential $ benefits of proposed rule due to increased leakage rates =	$1.54 million.
(Potential $ benefits of increased leakage rates − $ costs) =	−($172,027).

TABLE 1—ECONOMIC ANALYSIS SUMMARY—Continued

Potential benefits in $ due to potential incident avoidance of oil spills and injuries =	$19.4 million.
Break-even risk reduction level =	8.07 percent.

The proposed rule is intended to address, among other things, issues that have developed since publication in 1988 (53 FR 10690) of the existing Subpart H rule. Since that time, oil and gas production on the OCS has moved into deeper waters, introducing new challenges for industry and BSEE. For example, industry has shown interest in employing new technologies, including foam firefighting systems; subsea pumping, water flooding, and gas lift; and new alloys and equipment for high temperature and high pressure wells. Many of the new provisions in the proposed rule would codify BSEE's policies pertaining to production safety systems. This proposed rule would codify essential elements included in existing guidance documents, make clear BSEE's basic expectations, and provide industry with a balance of predictability and flexibility to address concerns related to offshore oil and natural gas production.

The BSEE is requesting comment on other options to consider, including alternatives to the specific provisions contained in the proposed rule, with the goal of ensuring a full discussion of these issues in advance of the final rule stage.

The BSEE retained a contractor to estimate the annual economic effect of this proposed rule on the offshore oil and natural gas production industry by comparing the costs and potential benefits of the new provisions in the proposed rule to the baseline (i.e., current practice in accordance with the 1988 rule, existing guidance documents, and industry standards). Existing impacts from the 1988 rule, DWOPs, NTLs, and API standards were not considered as costs and benefits of this proposed rule because they are part of the baseline. The analysis covered 10 years (2012 through 2021) to capture all major costs and potential benefits that could result from this proposed rule and presents the estimated annual effects, as well as the 10-year discounted totals using discount rates of 3 and 7 percent.

The BSEE welcomes comments on this analysis, including potential sources of data or information on the costs and potential benefits of this proposed rule. In summary, the contractor monetized the costs of the proposed rule for all the following provisions determined to result in a change from baseline: Reporting after a failure of SPPE equipment; notifying BSEE of production safety issues; certification for designs of mechanical and electrical systems; certification letter for mechanical and electrical systems installed in accordance with approved designs; certification of as-built diagrams of schematic piping and instrumentation diagrams and the safety analysis flow diagram; As-built piping and instrumentation diagrams to be maintained at a secure onshore location; inspection, testing, and certification of foam firefighting systems; inspection of fired and exhaust heated components; and submission of a contact list for OCS platforms. The analysis also considered the time required for industry staff to read and familiarize themselves with the new regulation. The total expected cost over 10 years of complying with these provisions is $16.87 million, or on average $1.7 million annually.

In addition, the analysis valued the expected potential benefits of the proposed rule by evaluating the increase of the allowable leakage rates for certain safety valves and by evaluating oil spills and injuries as a whole. This proposed rule intends to address the unnecessary repair or replacement of certain safety valves due to a higher allowable leakage rate and reduce the number of incidents resulting in oil spills and injuries. Thus, the total benefits of the rule consist of potential benefits for increasing the allowable leakage rates of certain safety devices and avoided damages. The potential benefit of allowing a higher leakage rate for certain safety valves is approximately $1.54 million annually. Using avoided cost factors developed for rulemaking in the wake of the Deepwater Horizon oil spill, the contractor estimated OCS facilities addressed by this rule account for an annual average of $19.4 million dollars in damages due to potential spills and injuries, for a total maximum potential benefit amount of $20.9 million. While the proposed rule is aimed at preventing oil spills and injuries, the actual reduction in the probability of incidents that the proposed rule would achieve is uncertain. Due to this uncertainty, BSEE was not able to perform a standard cost-benefit analysis estimating the net benefits of the proposed rule. As is common in situations where regulatory benefits are highly uncertain, a break-even analysis, which estimates the minimum risk reduction the proposed rule would need to achieve for the rule to be cost-beneficial. However, the potential benefits of the proposed rule only need to reduce these baseline adverse effects by between 8 and 9 percent to be considered cost-effective. This break-even analysis result suggests that the proposed rule would be beneficial even if it resulted in only one or two fewer typical incidents annually than the average of about 200 per year that happen under the baseline conditions.

Thus, BSEE has concluded that the proposed rule would produce substantial benefits that justify the compliance costs that it would impose.

Executive Order 13563 reaffirms the principles of E.O. 12866 while calling for improvements in the Nation's regulatory system to promote predictability, to reduce uncertainty, and to use the best, most innovative, and least burdensome tools for achieving regulatory ends. The executive order directs agencies to consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the public where these approaches are relevant, feasible, and consistent with regulatory objectives. E.O. 13563 emphasizes further that regulations must be based on the best available science and that the rulemaking process must allow for public participation and an open exchange of ideas. The BSEE works closely with engineers and technical staff to ensure this rulemaking utilizes sound engineering principles and options through research, standards development, and interaction with industry. Thus, we have developed this rule in a manner consistent with these requirements.

Regulatory Flexibility Act

The DOI certifies that this proposed rule would not have a significant economic effect on a substantial number of small entities as defined under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*).

The Regulatory Flexibility Act (RFA) at 5 U.S.C. 603 requires agencies to prepare a regulatory flexibility analysis to determine whether a regulation would have a significant economic impact on a substantial number of small entities. Section 605 of the RFA allows an agency to certify a rule in lieu of preparing an analysis if the regulation is not expected to have a significant economic impact on a substantial number of small entities. Further, under the Small Business Regulatory Enforcement Fairness Act of 1996, 5 U.S.C. 801 (SBREFA), an agency is required to produce compliance guidance for small entities if the rule has a significant economic impact. For the reasons explained in this section, BSEE believes this rule is not likely to have a significant economic impact and, therefore, an initial regulatory flexibility analysis is not required by the RFA. However, in the interest of transparency, BSEE had a contractor prepare an Initial Regulatory Flexibility Analysis (IRFA) to assess the impact of this proposed rule on small entities, as defined by the applicable Small Business Administration (SBA) size standards. The following discussions summarize the IRFA; however, a copy of the complete IRFA can be viewed at *www.Regulations.gov* (use the keyword/ID ''BSEE–2012–0005'').

a. Reasons BSEE Is Considering Action

The BSEE identified a need to revise Subpart H, Oil and Gas Production Safety Systems, which addresses production safety systems, subsurface safety devices, and safety device testing used in oil and natural gas production on the OCS, among other issues. These systems play a critical role in protecting workers and the environment. However, BSEE has not revised the regulation since its publication in 1988 (53 FR 10690). Since that time, oil and gas production on the OCS has moved into deeper waters, introducing new challenges for industry and BSEE. Many of the new provisions in the proposed rule would codify BSEE guidance and incorporate current industry practice. In addition, the wording and structure of the 1988 rule creates confusion about the requirements. The BSEE has rewritten and reorganized the rule to clarify existing requirements and highlight important information. These revisions would significantly improve readability of the regulation.

b. Description and Estimated Number of Small Entities Regulated

A small entity is one that is ''independently owned and operated and which is not dominant in its field of operation.'' The definition of small business varies from industry to industry in order to properly reflect industry size differences.

The proposed rule would affect operators and holders of Federal oil and gas leases, as well as pipeline right-of-way holders, on the OCS. The BSEE's analysis shows that this includes about 130 companies with active operations. Entities that operate under this rule fall under the SBA's North American Industry Classification System (NAICS) codes 211111 (Crude Petroleum and Natural Gas Extraction) and 213111 (Drilling Oil and Gas Wells). For these NAICS classifications, a small company is defined as one with fewer than 500 employees. Based on this criterion, approximately 90 (69 percent) of the companies operating on the OCS are considered small and the rest are considered large businesses. Therefore, BSEE estimates that the proposed rule would affect a substantial number of small entities.

c. Description and Estimate of Compliance Requirements

The BSEE has estimated the incremental costs for small operators, lease holders, and right-of-way holders in the offshore oil and natural gas production industry. Costs that already existed as a result of the 1988 rule, DWOPs, and currently-incorporated API standards were not considered as costs of this rule because they are part of the baseline. We have estimated the costs of the following provisions of the proposed rule: Reporting after a failure of SPPE equipment; notifying BSEE about production technical issues; certification, submission, and maintenance of designs and diagrams; inspection, testing, and certification of foam firefighting systems; inspection of fired and exhaust heated components; submission of contact list for OCS platforms; and familiarization with the new regulation.

Table 2 below shows the annual costs per small entity. Because most small entities would not be subject to all of the rule provisions, we also calculated the most likely impact on small entities, or the impact associated with only incurring the cost for the provisions for foam firefighting systems, inspection of fired and exhaust heated components, submission of contact list, and familiarization with the new regulations. This calculation resulted in a most likely average annual cost per affected small entity of $5,906 as shown in Table 2. In addition, we calculated a ''complete compliance scenario'' impact for an entity that would incur the costs of all of the rule provisions. As shown in Table 2, this complete compliance scenario impact is $8,183 per affected entity.

We then calculated the impact on small entities for these three scenarios as a percentage of the average revenues for small entities in the affected industries.

TABLE 2—ANNUAL COST PER SMALL ENTITY

[10-Year average][1]

	10-Year average
(1) Reporting after a failure of SPPE equipment	$168
(2) Notifying BSEE about technical issues	378
(3) Certification, submission, and maintenance of designs and diagrams	1,730
(4) Inspection, testing, and certification of foam firefighting systems	757
(5) Five-year inspection of fired and exhaust heated components	5,000
(6) Submission of contact list for OCS platforms	127
(7) Familiarization with new regulation	22
Most likely average annual cost per small entity (4 + 5 + 6 + 7)	5,906
Complete compliance scenario average annual cost per small entity	8,183

[1] Totals may not add because of rounding.

As shown in Table 3, the average costs of the two scenarios represent far less than 1 percent of average annual revenues for small entities in the affected industries.

TABLE 3—COST AS A PERCENTAGE OF REVENUE

Average revenue of a small business	45,700,000	
	Cost	Cost/revenue (percent)
Most likely total (4 + 5 + 6 + 7)	$5,906	0.013
Complete compliance scenario cost total	8,183	0.018

Based on this analysis, BSEE believes that this proposed rule would have a limited net direct cost impact on small operators, lease holders, and pipeline right-of-way holders beyond the baseline costs currently imposed by regulations with which industry already complies. The BSEE concludes that this proposed rule would not have a significant economic impact on a substantial number of small entities.

d. Description of Significant Alternatives to the Proposed Rule

The operating risk for small companies to incur safety or environmental accidents is not necessarily lower than it is for larger companies. Offshore operations are highly technical and can be hazardous. Adverse consequences in the event of incidents are the same regardless of the operator's size. The proposed rule would reduce risk for entities of all sizes. Nonetheless, BSEE is requesting comment on the costs of these proposed policies on small entities, with the goal of ensuring thorough consideration and discussion at the final rule stage. We specifically request comments on the burden estimates discussed above as well as information on regulatory alternatives that would reduce the burden on small entities (e.g., different compliance requirements for small entities, alternative testing requirements and periods, and exemption from regulatory requirements).

Your comments are important. The Small Business and Agriculture Regulatory Enforcement Ombudsman and 10 Regional Fairness Boards were established to receive comments from small businesses about Federal agency enforcement actions. The Ombudsman will annually evaluate the enforcement activities and rate each agency's responsiveness to small business. If you wish to comment on the actions of BSEE, call 1–888–734–3247. You may comment to the Small Business Administration without fear of retaliation. Allegations of discrimination/retaliation filed with the Small Business Administration will be investigated for appropriate action.

Small Business Regulatory Enforcement Fairness Act

The proposed rule is not a major rule under the Small Business Regulatory Enforcement Fairness Act (5 U.S.C. 801 *et seq.*). This proposed rule:

a. Would not have an annual effect on the economy of $100 million or more. This proposed rule would revise the requirements for oil and gas production safety systems. The changes would not have an impact on the economy or any economic sector, productivity, jobs, the environment, or other units of government. Most of the new requirements are related to inspection, testing, and paperwork requirements, and would not add significant time to development and production processes. The complete annual compliance cost for each affected small entity is estimated at $8,183.

b. Would not cause a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions.

c. Would not have significant adverse effects on competition, employment, investment, productivity, innovation, or the ability of U.S.-based enterprises to compete with foreign-based enterprises. The requirements will apply to all entities operating on the OCS.

Unfunded Mandates Reform Act of 1995

This proposed rule would not impose an unfunded mandate on State, local, or tribal governments or the private sector of more than $100 million per year. The proposed rule would not have a significant or unique effect on State, local, or tribal governments or the private sector. A statement containing the information required by Unfunded Mandates Reform Act (2 U.S.C. 1531 *et seq.*) is not required.

Takings Implication Assessment (Executive Order 12630)

Under the criteria in E.O. 12630, this proposed rule does not have significant takings implications. The proposed rule is not a governmental action capable of interference with constitutionally protected property rights. A Takings Implications Assessment is not required.

Federalism (Executive Order 13132)

Under the criteria in E.O. 13132, this proposed rule does not have federalism implications. This proposed rule would not substantially and directly affect the relationship between the Federal and State governments. To the extent that State and local governments have a role in OCS activities, this proposed rule would not affect that role. A Federalism Assessment is not required.

The BSEE has the authority to regulate offshore oil and gas production. State governments do not have authority over offshore production in Federal waters. None of the changes in this proposed rule would affect areas that are under the jurisdiction of the States. It would not change the way that the States and the Federal government interact, or the way that States interact with private companies.

Civil Justice Reform (Executive Order 12988)

This rule complies with the requirements of E.O. 12988. Specifically, this rule:

(a) Meets the criteria of section 3(a) requiring that all regulations be reviewed to eliminate errors, ambiguity, and be written to minimize litigation; and

(b) meets the criteria of section 3(b)(2) requiring that all regulations be written in clear language and contain clear legal standards.

Consultation With Indian Tribes (Executive Order 13175)

Under the criteria in E.O. 13175, we have evaluated this proposed rule and determined that it has no potential effects on federally recognized Indian tribes.

Paperwork Reduction Act (PRA) of 1995

This proposed rule contains a collection of information that will be submitted to the Office of Management and Budget (OMB) for review and approval under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*). As part of our continuing effort to reduce paperwork and respondent burdens, BSEE invites the public and other Federal agencies to comment on any aspect of the reporting and recordkeeping burden. If you wish to comment on the information collection (IC) aspects of this proposed rule, you may send your comments directly to OMB and send a copy of your comments to the Regulations and Standards Branch (see the **ADDRESSES** section of this proposed rule). Please reference; 30 CFR Part 250, Subpart H, *Oil and Gas Production Safety Systems,* 1014–0003, in your comments. You may obtain a copy of the supporting statement for the new collection of information by contacting the Bureau's Information Collection Clearance Officer at (703) 787–1607. To see a copy of the entire ICR submitted to OMB, go to *http://www.reginfo.gov* (select Information Collection Review, Currently Under Review).

The PRA provides that an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. OMB is required to make a decision concerning the collection of information contained in these proposed regulations 30 to 60 days after publication of this document in the **Federal Register**.

Therefore, a comment to OMB is best assured of having its full effect if OMB receives it by September 23, 2013. This does not affect the deadline for the public to comment to BSEE on the proposed regulations.

The title of the collection of information for this rule is 30 CFR Part 250, Subpart H, *Oil and Gas Production Safety Systems* (Proposed Rulemaking). The proposed regulations concern oil and gas production requirements, and the information is used in our efforts to protect life and the environment, conserve natural resources, and prevent waste.

Potential respondents comprise Federal OCS oil, gas, and sulphur operators and lessees. The frequency of response varies depending upon the requirement. Responses to this collection of information are mandatory, or are required to obtain or retain a benefit; they are also submitted on occasion, annually, and as a result of situations encountered depending upon the requirement. The IC does not include questions of a sensitive nature. The BSEE will protect proprietary information according to the Freedom of Information Act (5 U.S.C. 552) and its implementing regulations (43 CFR part 2), 30 CFR part 252, *OCS Oil and Gas Information Program,* and 30 CFR 250.197, *Data and information to be made available to the public or for limited inspection.*

As discussed earlier in the preamble, the proposed rule is a complete revision of the current subpart H. It incorporates guidance from several NTLs that respondents currently follow, and would codify various conditions that BSEE imposes when approving production safety systems to ensure that they are installed and operated in a safe and environmentally sound manner. OMB approved the IC burden of the current 30 CFR part 250, subpart H regulations under control number 1014–0003 (62,963 burden hours; and $343,794 non-hour cost burdens). When the final revised subpart H regulations take effect, the IC burden approved for this rulemaking will replace the collection under 1014–0003 in its entirety.

There is also a revised paragraph (c)(2) proposed for 30 CFR 250.107 that would impose a new IC requirement. The paperwork burden for this proposed regulation is included in the submission to OMB for approval of the proposed IC for subpart H. When this rulemaking becomes final, the 30 CFR Part 250, Subpart A, paperwork burden would be removed from this collection of information and consolidated with the IC burden under OMB Control Number 1014–0022, 30 CFR Part 250, Subpart A, General.

The following table provides a breakdown of the paperwork and non-hour cost burdens for this proposed rulemaking. For the current requirements retained in the proposed rule, we used the approved estimated hour burdens and the average number of annual responses where discernible. However, there are several new requirements in the proposed rule as follows:

- Under subpart A, (§ 250.107(c)), we have added proposed BAST requirements (+10 hours).
- Under General Requirements (§ 250.802–803), we have added proposed SPPE life cycle analysis requirements (+132 hours).
- A proposed new section, Subsea and Subsurface Safety Systems—Subsea Trees (§§ 250.825–833) would add new burden requirements (+24 hours).
- Under Production Safety Systems (§ 250.842), we added proposed certification requirements as well as documentation of these requirements (+608 hours).
- In various proposed requirements, requests for unique, specific approvals (+61 hours).
- A proposed new section, (§ 250.861(b)) would add new requirements pertaining to submission of foam samples annually for testing (+1,000 hours).
- A proposed new section, (§ 250.867) would add new requirements pertaining to submittals for temporary quarters, firewater systems, or equipment (+307 hours).
- A proposed new section, (§ 250.870) added documentation requirements (+3 hours).
- In § 250.860, we proposed submittal notification and/or recordkeeping of minor and major changes using chemical only fire prevention system (+7 hours).
- Proposed new, (§ 250.890) added an annual contact list submittal (+550 hours).

Current subpart H regulations have 62,963 hours and $343,794 non-hour cost burdens approved by OMB. This revision to the collection requests a total of 65,665 hours which is a burden hour net increase of 2,702 hours. The non-hour cost burdens are unchanged. With the exception of items identified as NEW in the following chart, the burden estimates shown are those that are estimated for the current subpart H regulations.

Citation 30 CFR 250, subpart A	Reporting and recordkeeping requirement	Hour burden	Average number of annual responses	Annual burden hours
107(c)(2)	NEW: Demonstrate to us that by using BAST the benefits are insufficient to justify the cost.	5	2 justifications	10
Subtotal			2 responses	10
Citation 30 CFR 250 Subpart H and NTL(s)	Reporting and Recordkeeping Requirement	Hour Burden	Average number of annual responses	Annual burden hours
		Non-Hour Cost Burdens*		
General Requirements				
800(a)	Requirements for your production safety system application.	Burden included with specific requirements below.		0
800(a); 880(a)	Prior to production, request approval of pre-production inspection; notify BSEE 72 hours before commencement so we may witness preproduction test and conduct inspection.	1	76 requests	76

Citation 30 CFR 250, subpart A	Reporting and recordkeeping requirement	Hour burden	Average number of annual responses	Annual burden hours
801(c)	Request evaluation and approval [OORP] of other quality assurance programs covering manufacture of SPPE.	2	1 request	2
802(c)(1); 852(e)(4); 861(b)	NEW: Submit statement/certification for: exposure functionality; pipe is suitable and manufacturer has complied with IVA; suitable firefighting foam per original manufacturer specifications.	Not considered IC under 5 CFR 1320.3(h)(1).		0
802(c)(5)	NEW: Document all manufacturing, traceability, quality control, and inspection requirements. Retain required documentation until 1 year after the date of decommissioning the equipment.	2	30 documents	60
803(a)	NEW: Within 30 days of discovery and identification of SPPE failure, provide a written report of equipment failure to manufacturer.	2	10 reports	20
803(b)	NEW: Document and determine the results of the SPPE failure within 60-days and corrective action taken.	5	10 documents	50
803(c)	NEW: Submit [OORP] modified procedures you made if notified by manufacturer of design changes or you changed operating or repair procedures as result of a failure, within 30 days.	2	1 submittal	2
804	Submit detailed info regarding installing SSVs in an HPHT environment with your APD, APM, DWOP etc.	Burdens are covered under 30 CFR Part 250, Subparts D and B, 1014–0018 and 1014–0024.		0
804(b); 829(b), (c); 841(b)	NEW: District Manager will approve on a case-by-case basis.	Not considered IC per 5 CFR 1320.3(h)(6).		0
Subtotal			128 responses	210
	Surface and Subsurface Safety Systems—Dry Trees			
810; 816; 825(a); 830	Submit request for a determination that a well is incapable of natural flow.	5¾	41 wells	246
	Verify the no-flow condition of the well annually	¼		
814(a); 821; 828(a); 838(c)(3); 859(b); 870(b).	Specific alternate approval requests requiring approval	Burden covered under 30 CFR part 250, subpart A, 1014–0022.		0
817(b); 869(a)	Identify well with sign on wellhead that subsurface safety device is removed; flag safety devices that are out of service; a visual indicator must be used to identify the bypassed safety device.	Usual/customary safety procedure for removing or identifying out-of-service safety devices.		0
817(b)	Record removal of subsurface safety device	Burden included in § 250.890 of this subpart.		0
817(c)	Request alternate approval of master valve [required to be submitted with an APM].	Burden covered under 30 CFR part 250, subpart D, 1014–0018.		0
Subtotal			41 responses	246
	Subsea and Subsurface Safety Systems—Subsea Trees			
		Notifications		
825(b); 831; 833; 837(c)(5); 838(c); 874(g)(2); 874(f).	NEW: Notify BSEE: (1) If you cannot test all valves and sensors; (2) 48 hours in advance if monitoring ability affected; (3) designating USV2 or another qualified valve; (4) resuming production; (5) 12 hours of detecting loss of communication; immediately if you cannot meet value closure conditions.	(1) ½ (2) 2 (3) 1 (4) ½ (5) ½	6 1 1 1 1	7
827	NEW: Request remote location approval	1	1 request	1

Citation 30 CFR 250, subpart A	Reporting and recordkeeping requirement	Hour burden	Average number of annual responses	Annual burden hours
831	NEW: Submit a repair/replacement plan to monitor and test.	2	1 submittal	2
837(a)	NEW: Request approval to not shut-in a subsea well in an emergency.	½	10 requests	5
837(b)	NEW: Prepare and submit for approval a plan to shut-in wells affected by a dropped object.	2	1 submittal	2
837(c)(2)	NEW: Obtain approval to resume production re P/L PSHL sensor.	½	2 approvals	1
838(a); 839(a)(2)	NEW: Verify closure time of USV upon request of District Manager.	2	2 verifications	4
838(c)(3)	NEW: Request approval to produce after loss of communication; include alternate valve closure table.	2	1 approval	2
Subtotal			28 responses	24
		Production Safety Systems		
842	Submit application, and all required/supporting information, for a production safety system with > 125 components.	16	1 application	16
		$5,030 per submission × 1 = $5,030 $13,238 per offshore visit × 1 = $13,238 $6,884 per shipyard visit × 1 = $6,884		
	25–125 components	13	10 applications	130
		$1,218 per submission × 10 = $12,180 $8,313 per offshore visit × 1 = $8,313 $4,766 per shipyard visit × 1 = $4,766		
	< 25 components	8	20 applications	160
		$604 per submission × 20 = $12,080		
	Submit modification to application for production safety system with > 125 components.	9	180 modifications	1,620
		$561 per submission × 180 = $100,980		
	25–125 components	7	758 modifications	5,306
		$201 per submission × 758 = $152,358		
	< 25 components	5	329 modifications	1,645
		$85 per submission × 329 = $27,965		
842(b)	NEW: Your application must also include certification(s) that the designs for mechanical and electrical systems were reviewed, approved, and stamped by registered professional engineer. [**Note:** Upon promulgation, these certification production safety systems requirements will be consolidated into the application hour burden for the specific components].	6	32 certifications	192
842(c)	NEW: Submit a certification letter that the mechanical and electrical systems were installed in accordance with approved designs.	6	32 letters	192
842(d), (e)	NEW: Submit a certification letter within 60-days after production that the as-built diagrams, piping, and instrumentation diagrams are on file, certified correct, and stamped by a registered professional engineer; submit all the as-built diagrams.	6 ½	32 letters	208

Citation 30 CFR 250, subpart A	Reporting and recordkeeping requirement	Hour burden	Average number of annual responses	Annual burden hours
842(f)	NEW: Maintain records pertaining to approved design and installation features and as-built pipe and instrumentation diagrams at your offshore field office or location available to the District Manager; make available to BSEE upon request and retained for the life of the facility.	½	32 records	16
Subtotal			1,426 responses	9,485
			$343,794 non-hour cost burdens	
Additional Production System Requirements				
851(a)(4)	NEW: Request approval to use uncoded pressure and fired vessels beyond their 18 months of continued use.	2	1 request	2
851(b); 852(a)(3); 858(c); 865(b).	Maintain [most current] pressure-recorder information at location available to the District Manager for as long as information is valid.	23	615 records	14,145
851(c)(2)	NEW: Request approval from District Manager for activation limits set less than 5 psi.	1	10 requests	10
852(c)(1)	NEW: Request approval from District Manager to vent to some other location.	1	10 requests	10
852(c)(2)	NEW: Request a different sized PSV	1	1 request	5
852(c)(2)	NEW: Request different upstream location of the PSV.	1	5 request	5
852(e)	Submit required design documentation for unbonded flexible pipe.	Burden is covered by the application requirement in § 250.842.		0
855(b)	Maintain ESD schematic listing control function of all safety devices at location conveniently available to the District Manager for the life of the facility.	15	615 listings	9,225
858(b)	NEW: Request approval from District Manager to use different procedure for gas-well gas affected.	1	1 request	1
859(a)(2)	Request approval for alternate firefighting system	Burden covered under 30 CFR part 250, subpart A, 1014–0022.		0
859(a)(3), (4)	Post diagram of firefighting system; furnish evidence firefighting system suitable for operations in subfreezing climates.	5	38 postings	190
859(b)	NEW: Request extension from District Manager up to 7 days of your approved departure to use chemicals.	Burden covered under 30 CFR part 250, subpart A, 1014–0022.		0
860(a); related NTL(s)	Request approval, including but not limited to, submittal of justification and risk assessment, to use chemical only fire prevention and control system in lieu of a water system.	22	31 requests	682
860(b)	NEW: Minor change(s) made after approval rec'd re 860(a)—document change; maintain the revised version at facility or closest field office for BSEE review/inspection; maintain for life of facility.	½	10 minor changes	5
860(b)	NEW: Major change(s) made after approval rec'd re 860(a)—submit new request w/updated risk assessment to District Manager for approval; maintain at facility or closest field office for BSEE review/inspection; maintain for life of facility.	2	1 major change	2
861(b)	NEW: Submit foam concentrate samples annually to manufacturer for testing.	2	500 submittals	1,000
864	Maintain erosion control program records for 2 years; make available to BSEE upon request.	12	615 records	7,380

Citation 30 CFR 250, subpart A	Reporting and recordkeeping requirement	Hour burden	Average number of annual responses	Annual burden hours
867(a)	NEW: Request approval from District Manager to install temporary quarters.	6	1 request	6
867(b)	NEW: Submit supporting information/documentation if required by District Manager to install a temporary firewater system.	1	1 request	1
867(c)	NEW: Request approval form District manager to use temporary equipment for well testing/clean-up.	1	300 requests	300
869(a)(3)	NEW: Request approval from District Manager to bypass an element of ESS.	1	2 requests	2
870	NEW: Document PSL on your field test records w/ delay greater than 45 seconds.	½	6 records	3
871	Request variance from District Manager on approved welding and burning practices.	Burden covered under 30 CFR part 250, subpart A—1014–0022.		0
874(g)(2), (3)	NEW: Submit request to District Manager with alternative plan ensuring subsea shutdown capability.	2	5 requests	10
874(g)(3)	NEW: Request approval from District Manager to forgo WISDV testing.	1	10 requests	10
874(f)(2)	NEW: Request approval from District Manager to continue to inject w/loss of communication.	1	5 requests	5
874(f)(2)	NEW: Request alternate hydraulic bleed schedule	Burden covered under 30 CFR part 250, subpart A, 1014–0022.		0
Subtotal			2,783 responses	32,999
Safety Device Testing				
880(a)(3)	NEW: Notify BSEE and receive approval before performing modifications to existing subsea infrastructure.	Burden covered under 30 CFR part 250, subpart A 1014–0022.		0
880(c)(5)(vi)	NEW: Request approval for disconnected well shut-in to exceed more than 2 years.	1	1 request	1
Subtotal			1 response	1
Records and Training				
890	Maintain records for 2 years on subsurface and surface safety devices to include, but limited to, status and history of each device; approved design & installation date and features, inspection, testing, repair, removal, adjustments, reinstallation, etc.; at field office nearest facility AND a secure onshore location; make records available to BSEE.	36	615 records	22,140
890(c)	NEW: Submit annually to District Manager a contact list for all OCS operated platforms or submit when revised.	½ ½	1,000 annual lists 100 revised lists	550
Subtotal			1,715 responses	22,690
Total Burden Hours			6,124 Responses	65,665
			$343,794 Non-Hour Cost Burdens	

The BSEE specifically solicits comments on the following:

(1) Is the IC necessary or useful for us to perform properly; (2) is the proposed burden accurate; (3) are there suggestions that will enhance the quality, usefulness, and clarity of the information to be collected; and (4) can we minimize the burden on the respondents, including the use of technology.

In addition, the PRA requires agencies to also estimate the non-hour paperwork cost burdens to respondents or recordkeepers resulting from the collection of information. Therefore, if you have other than hour burden costs to generate, maintain, and disclose this information, you should comment and provide your total capital and startup cost components or annual operation, maintenance, and purchase of service components. Generally, your estimate should not include burdens other than those associated with the provision of information to, or recordkeeping for the government; or burdens that are part of customary and usual business or private practices. For further information on this non-hour burden estimation process, refer to 5 CFR 1320.3(b)(1) and (2), or contact the BSEE Bureau Information Collection Clearance Officer.

National Environmental Policy Act of 1969

We prepared an environmental assessment to determine whether this proposed rule would have a significant impact on the quality of the human environment under the National Environmental Policy Act of 1969. This proposed rule does not constitute a major Federal action significantly affecting the quality of the human environment. A detailed statement under the National Environmental Policy Act of 1969 is not required because we reached a Finding of No Significant Impact (FONSI). A copy of the FONSI and Environmental Assessment can be viewed at *www.Regulations.gov* (use the keyword/ ID ''BSEE–2012–0005'').

Data Quality Act

In developing this rule we did not conduct or use a study, experiment, or survey requiring peer review under the Data Quality Act (Pub. L. 106–554, app. C § 515, 114 Stat. 2763, 2763A–153–154).

Effects on the Nation's Energy Supply (Executive Order 13211)

This proposed rule is not a significant energy action under the definition in E.O. 13211. A Statement of Energy Effects is not required.

Clarity of This Regulation (Executive Order 12866)

We are required by E.O. 12866, E.O. 12988, and by the Presidential Memorandum of June 1, 1998, to write all rules in plain language. This means that each rule we publish must:

(a) Be logically organized;

(b) use the active voice to address readers directly;

(c) use clear language rather than jargon;

(d) be divided into short sections and sentences; and

(e) use lists and tables wherever possible.

If you feel that we have not met these requirements, send us comments by one of the methods listed in the ADDRESSES section. To better help us revise the rule, your comments should be as specific as possible. For example, you should tell us the numbers of the sections or paragraphs that you find unclear, which sections or sentences are too long, the sections where you feel lists or tables would be useful, etc.

Public Availability of Comments

Before including your address, phone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

List of Subjects in 30 CFR Part 250

Administrative practice and procedure, Continental shelf, Environmental impact statements, Environmental protection, Government contracts, Incorporation by reference, Investigations, Oil and gas exploration, Penalties, Pipelines, Public lands—mineral resources, Public lands—rights-of-way, Reporting and recordkeeping requirements, Sulphur.

Dated: August 6, 2013.

Tommy Beaudreau,

Acting Assistant Secretary—Land and Minerals Management.

For the reasons stated in the preamble, the Bureau of Safety and Environmental Enforcement (BSEE) proposes to amend 30 CFR Part 250 as follows:

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

■ 1. The authority citation for part 250 continues to read as follows:

Authority: 30 U.S.C. 1751; 31 U.S.C. 9701; 43 U.S.C. 1334.

■ 2. Amend § 250.107 by revising paragraph (c) and removing paragraph (d) to read as follows:

§ 250.107 What must I do to protect health, safety, property, and the environment?

* * * * *

(c)(1) Wherever failure of equipment may have a significant effect on safety, health, or the environment, you must use the best available and safest technology (BAST) that BSEE determines to be economically feasible on:

(i) All new drilling and production operations and

(ii) Wherever practicable, on existing operations.

(2) You may request an exception by demonstrating to BSEE that the incremental benefits of using BAST are clearly insufficient to justify the incremental costs of utilizing such technologies.

■ 3. Revise § 250.125(a)(10), (11), (12), (13), (14), and (15) to read as follows:

§ 250.125 Service fees.

(a) * * *

Service—processing of the following:	Fee amount	30 CFR citation
* * *	* * *	*
(10) New Facility Production Safety System Application for facility with more than 125 components.	$5,030 A component is a piece of equipment or ancillary system that is protected by one or more of the safety devices required by API RP 14C (as incorporated by reference in § 250.198); $13,238 additional fee will be charged if BSEE deems it necessary to visit a facility offshore, and $6,884 to visit a facility in a shipyard.	§ 250.842
(11) New Facility Production Safety System Application for facility with 25–125 components.	$1,218 Additional fee of $8,313 will be charged if BSEE deems it necessary to visit a facility offshore, and $4,766 to visit a facility in a shipyard.	§ 250.842
(12) New Facility Production Safety System Application for facility with fewer than 25 components.	$604	§ 250.842
(13) Production Safety System Application—Modification with more than 125 components reviewed.	$561	§ 250.842

Service—processing of the following:	Fee amount	30 CFR citation
(14) Production Safety System Application—Modification with 25–125 components reviewed.	$201	§ 250.842
(15) Production Safety System Application—Modification with fewer than 25 components reviewed..	$85	§ 250.842
* * *	* * *	*

■ 4. Amend § 250.198 as follows:
■ a. Remove paragraphs (g)(6) and (g)(7);
■ b. Redesignate paragraph (g)(8) as (g)(6);
■ c. Revise paragraphs (g)(1) through (g)(3), (h)(1), (h)(51) through (h)(53), (h)(55) through (h)(62), (h)(65), (h)(66), (h)(68), (h)(70), (h)(71), (h)(73), and (h)(74); and
■ d. Add new paragraph (h)(89) to read as follows:

§ 250.198 Documents incorporated by reference.

* * * * *

(g) * * *

(1) ANSI/ASME Boiler and Pressure Vessel Code, Section I, Rules for Construction of Power Boilers; including Appendices, 2004 Edition; and July 1, 2005 Addenda, and all Section I Interpretations Volume 55, incorporated by reference at §§ 250.851(a)(1)(i), (a)(4)(iii), (a)(5)(i), and 250.1629(b)(1), (b)(1)(i).

(2) ANSI/ASME Boiler and Pressure Vessel Code, Section IV, Rules for Construction of Heating Boilers; including Appendices 1, 2, 3, 5, 6, and Non-mandatory Appendices B, C, D, E, F, H, I, K, L, and M, and the Guide to Manufacturers Data Report Forms, 2004 Edition; July 1, 2005 Addenda, and all Section IV Interpretations Volume 55, incorporated by reference at §§ 250.851(a)(1)(i), (a)(4)(iii), (a)(5)(i), and 250.1629(b)(1), (b)(1)(i).

(3) ANSI/ASME Boiler and Pressure Vessel Code, Section VIII, Rules for Construction of Pressure Vessels; Divisions 1 and 2, 2004 Edition; July 1, 2005 Addenda, Divisions 1, 2, and 3 and all Section VIII Interpretations Volumes 54 and 55, incorporated by reference at §§ 250.851(a)(1)(i), (a)(4)(iii), (a)(5)(i), and 250.1629(b)(1), (b)(1)(i).

* * * * *

(h) * * *

(1) API 510, Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration, Downstream Segment, Ninth Edition, June 2006, Product No. C51009; incorporated by reference at §§ 250.851(a)(1)(ii) and 250.1629(b)(1);

* * * * *

(51) API RP 2RD, Recommended Practice for Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), First Edition, June 1998; reaffirmed, May 2006, Errata, June 2009; Order No. G02RD1; incorporated by reference at §§ 250.800(c)(2), 250.901(a), (d), and 250.1002(b)(5);

(52) API RP 2SK, Recommended Practice for Design and Analysis of Stationkeeping Systems for Floating Structures, Third Edition, October 2005, Addendum, May 2008, Product No. G2SK03; incorporated by reference at §§ 250.800(c)(3) and 250.901(a), (d);

(53) API RP 2SM, Recommended Practice for Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring, First Edition, March 2001, Addendum, May 2007; incorporated by reference at §§ 250.800(c)(3) and 250.901;

* * * * *

(55) API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems, ANSI/API Recommended Practice 14B, Fifth Edition, October 2005, also available as ISO 10417: 2004, (Identical) Petroleum and natural gas industries—Subsurface safety valve systems—Design, installation, operation and redress, Product No. GX14B05; incorporated by reference at §§ 250.802(b), 250.803(a), 250.814(d), 250.828(c), and 250.880(c)(1)(i), (c)(4)(i), (c)(5)(ii)(A);

(56) API RP 14C, Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms, Seventh Edition, March 2001, Reaffirmed: March 2007; Product No. C14C07; incorporated by reference at §§ 250.125(a)(10), 250.292(j), 250.841(a), 250.842(a)(2), 250.850, 250.852(a)(1), 250.855, 250.858(a), 250.862(e), 250.867(a), 250.869(a)(3), (b), (c), 250.872(a), 250.873(a), 250.874(a), 250.880(b)(2), (c)(2)(v), 250.1002(d), 250.1004(b)(9), 250.1628(c), (d)(2), 250.1629(b)(2), (b)(4)(v), and 250.1630(a);

(57) API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, Fifth Edition, October 1991; Reaffirmed, March 2007, Order No. 811–07185; incorporated by reference at §§ 250.841(b), 250.842(a)(1), and 250.1628(b)(2), (d)(3);

(58) API RP 14F, Recommended Practice for Design, Installation, and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class 1, Division 1 and Division 2 Locations, Upstream Segment, Fifth Edition, July 2008, Product No. G14F05; incorporated by reference §§ 250.114(c), 250.842(b)(1), 250.862(e), and 250.1629(b)(4)(v);

(59) API RP 14FZ, Recommended Practice for Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Zone 0, Zone 1 and Zone 2 Locations, First Edition, September 2001, Reaffirmed: March 2007; Product No. G14FZ1; incorporated by reference at §§ 250.114(c), 250.842(b)(1), 250.862(e), and 250.1629(b)(4)(v);

(60) API RP 14G, Recommended Practice for Fire Prevention and Control on Fixed Open-type Offshore Production Platforms, Fourth Edition, April 2007; Product No. G14G04; incorporated by reference at §§ 250.859(a), 250.862(e), and 250.1629(b)(3), (b)(4)(v);

(61) API RP 14H, Recommended Practice for Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore, Fifth Edition, August 2007, Product No. G14H05; incorporated by reference at §§ 250.820, 250.834, 250.836, and 250.880(c)(2)(iv), (c)(4)(iii);

(62) API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, Second Edition, May 2001; Reaffirmed: March 2007; Product No. G14J02; incorporated by reference at §§ 250.800(b), (c)(1), 250.842(b)(3), and 250.901(a)(14);

* * * * *

(65) API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2, Second Edition, November 1997; Errata August 17, 1998,

Reaffirmed November 2002, API Stock No. C50002; incorporated by reference at §§ 250.114(a), 250.459, 250.842(a)(1), (a)(3)(i), 250.862(a), (e), 250.872(a), 250.1628(b)(3), (d)(4)(i), and 250.1629(b)(4)(i);

(66) API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2, First Edition, November 1997; Errata August 17, 1998, American National Standards Institute, ANSI/API RP 505–1998, Approved: January 7, 1998, Order No. C50501; incorporated by reference at §§ 250.114(a), 250.459, 250.842(a)(1), (a)(3)(i), 250.862(a), (e), 250.872(a), 250.1628(b)(3), (d)(4)(i), and 250.1629(b)(4)(i);

* * * * *

(68) ANSI/API Spec. Q1, Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry, Eighth Edition, December 2007, Effective Date: June 15, 2008, Addendum 1, June 2010, Effective Date: December 1, 2010; also available as ISO TS 29001:2007 (Identical), Petroleum, petrochemical and natural gas industries—Sector specific requirements—Requirements for product and service supply organizations, Effective Date: December 15, 2003, API Stock No. GQ1007; incorporated by reference at § 250.801(b), (c);

* * * * *

(70) API Spec. 6A, Specification for Wellhead and Christmas Tree Equipment, Nineteenth Edition, July 2004, Effective Date: February 1, 2005; Contains API Monogram Annex as part of US National Adoption; also available as ISO 10423:2003 (Modified), Petroleum and natural gas industries—Drilling and production equipment—Wellhead and Christmas tree equipment; Errata 1, September 2004, Errata 2, April 2005, Errata 3, June 2006, Errata 4, August 2007, Errata 5, May 2009, Addendum 1, February 2008, Addendum 2, December 2008, Addendum 3, December 2008, Addendum 4, December 2008, Product No. GX06A19; incorporated by reference at §§ 250.802(a), 250.803(a), 250.873(b), (b)(3)(iii), 250.874(g)(2) and 250.1002 (b)(1), (b)(2);

(71) API Spec. 6AV1, Specification for Verification Test of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service, First Edition, February 1, 1996; reaffirmed January 2003, API Stock No. G06AV1; incorporated by reference at §§ 250.802(a), 250.833, 250.873(b) and 250.874(g)(2);

* * * * *

(73) ANSI/API Spec. 14A, Specification for Subsurface Safety Valve Equipment, Eleventh Edition, October 2005, Effective Date: May 1, 2006; also available as ISO 10432:2004 (Identical), Petroleum and natural gas industries—Downhole equipment—Subsurface safety valve equipment, Product No. GX14A11; incorporated by reference at §§ 250.802(b) and 250.803(a)

(74) ANSI/API Spec. 17J, Specification for Unbonded Flexible Pipe, Third Edition, July 2008, Effective Date: January 1, 2009, Contains API Monogram Annex as part of US National Adoption; also available as ISO 13628–2:2006 (Identical), Petroleum and natural gas industries—Design and operation of subsea production systems—Part 2: Unbonded flexible pipe systems for subsea and marine application; Product No. GX17J03; incorporated by reference at §§ 250.852(e)(1), (e)(4), 250.1002(b)(4), and 250.1007(a)(4)(i)(D).

* * * * *

(89) API 570 Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems, Third Edition, November 2009; Product No. C57003; incorporated by reference at § 250.841(b).

■ 5. Revise § 250.517(e) to read as follows:

§ 250. 517 Tubing and wellhead equipment.

* * * * *

(e) Subsurface safety equipment must be installed, maintained, and tested in compliance with the applicable sections in §§ 250.810 through 250.839 of this part.

■ 6. Revise § 250.618(e) to read as follows:

§ 250.618 Tubing and wellhead equipment.

* * * * *

(e) Subsurface safety equipment must be installed, maintained, and tested in compliance with the applicable sections in §§ 250.810 through 250.839 of this part.

■ 7. Revise subpart H to read as follows:

Subpart H—Oil and Gas Production Safety Systems

General Requirements

Sec.

Surface and Subsurface Safety Systems—Dry Trees

Subsea and Subsurface Safety Systems—Subsea Trees

Production Safety Systems

General Requirements

§ 250.800 General.

(a) You must design, install, use, maintain, and test production safety equipment in a manner to ensure the safety and protection of the human, marine, and coastal environments. For production safety systems operated in subfreezing climates, you must use equipment and procedures that account for floating ice, icing, and other extreme environmental conditions that may occur in the area. You must not commence production until BSEE approves your production safety system application and you have requested a preproduction inspection.

(b) For all new production systems on fixed leg platforms, you must comply with API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities (incorporated by reference as specified in § 250.198);

(c) For all new floating production systems (FPSs) (*e.g.,* column-stabilized-units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); spars, etc.), you must:

(1) Comply with API RP 14J;

(2) Meet the drilling, well completion, well workover, and well production riser standards of API RP 2RD, Recommended Practice for Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs) (incorporated by reference as specified in § 250.198). Beginning 1 year from the publication date of the final rule and thereafter, you are prohibited from installing single bore production risers from floating production facilities.

(3) Design all stationkeeping systems for floating production facilities to meet the standards of API RP 2SK, Design and Analysis of Stationkeeping Systems for Floating Structures and API RP 2SM, Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring (both incorporated by reference as specified in § 250.198), as well as relevant U.S. Coast Guard regulations; and

(4) Design stationkeeping systems for floating facilities to meet the structural requirements of §§ 250.900 through 250.921.

§ 250.801 Safety and pollution prevention equipment (SPPE) certification.

(a) *SPPE equipment.* In wells located on the OCS, you must install only safety and pollution prevention equipment (SPPE) considered certified under paragraph (b) of this section or accepted under paragraph (c) of this section. The BSEE considers the following equipment to be types of SPPE:

(1) Surface safety valves (SSV) and actuators, including those installed on injection wells capable of natural flow;

(2) Boarding shut down valves (BSDV), 1 year after the date of publication of the final rule;

(3) Underwater safety valves (USV) and actuators; and

(4) Subsurface safety valves (SSSV) and associated safety valve locks and landing nipples. Subsurface-controlled SSSVs are not allowed on subsea wells.

(b) *Certification of SPPE.* SPPE equipment that is manufactured and marked pursuant to API Spec. Q1, Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry (ISO TS 29001:2007) (incorporated by reference as specified in § 250.198), is considered certified SPPE under this part. The BSEE considers all other SPPE as noncertified unless approved in accordance with 250.801(c).

(c) *Accepting SPPE manufactured under other quality assurance programs.* The BSEE may exercise its discretion to accept SPPE manufactured under quality assurance programs other than API Spec. Q1 (ISO TS 29001:2007), provided an operator submits a request to BSEE containing relevant information about the alternative program under § 250.141, and receives BSEE approval. Such requests should be submitted to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; HE 3314; 381 Elden Street; Herndon, Virginia 20170–4817.

§ 250.802 Requirements for SPPE.

(a) All SSVs, BSDVs, and USVs must meet all of the specifications contained in API/ANSI Spec. 6A, Specification for Wellhead and Christmas Tree Equipment, (ISO 10423:2003); and Spec. 6AV1, Specification for Verification Test of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service (both incorporated by reference as specified in § 250.198).

(b) All SSSVs must meet all of the specifications and recommended practices of API/ANSI Spec. 14A, Specification for Subsurface Safety Valve Equipment (ISO 10432:2004) and ANSI/API RP 14B, Recommended Practice for Design, Installation, and Operation of Subsurface Safety Valve Systems (ISO 10417:2004), including all Annexes (both incorporated by reference as specified in § 250.198).

(c) Requirements derived from the documents incorporated in this section for SSVs, BSDVs, USVs, and SSSVs, include, but are not limited to, the following:

(1) Each device must be designed to function and to close at the most extreme conditions to which it may be exposed, including temperature, pressure, flow rates, and environmental conditions. You must have an independent third party review and certify that each device will function as designed under the conditions to which it may be exposed. The independent third party must have sufficient expertise and experience to perform the review and certification.

(2) All materials and parts must meet the original equipment manufacturer specifications and acceptance criteria.

(3) The device must pass applicable validation tests and functional tests performed by an API-licensed test agency.

(4) You must have requalification testing performed following manufacture design changes.

(5) You must comply with and document all manufacturing, traceability, quality control, and inspection requirements.

(6) You must follow specified installation, testing, and repair protocols.

(7) You must use only qualified parts, procedures, and personnel to repair or redress equipment.

(d) You must install certified SPPE according to the following table.

If . . .	Then . . .
(1) You need to install any SPPE	You must install certified SPPE.
(2) A non-certified SPPE is already in service	It may remain in service on that well.
(3) A non-certified SPPE requires offsite repair, re-manufacturing, or any hot work such as welding.	You must replace it with certified SPPE.

(e) You must retain all documentation related to the manufacture, installation, testing, repair, redress, and performance of the SPPE equipment until 1 year after the date of decommissioning of the equipment.

§ 250.803 What SPPE failure reporting procedures must I follow?

(a) You must follow the failure reporting requirements contained in section 10.20.7.4 of API Spec. 6A for SSVs, BSDVs, and USVs and section 7.10 of API Spec. 14A and Annex F of API RP 14B for SSSVs (all incorporated by reference in § 250.198). You must provide a written report of equipment failure to the manufacturer of such equipment within 30 days after the discovery and identification of the failure. A failure is any condition that prevents the equipment from meeting the functional specification.

(b) You must ensure that an investigation and a failure analysis are performed within 60 days of the failure to determine the cause of the failure. You must also ensure that the results and any corrective action are documented. If the investigation and analysis are performed by an entity other than the manufacturer, you must ensure that the manufacturer receives a copy of the analysis report.

(c) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such changes, report the design change or modified procedures in writing to the Chief of Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; HE 3314; 381 Elden Street; Herndon, Virginia 20170–4817.

§ 250.804 Additional requirements for subsurface safety valves (SSSVs) and related equipment installed in high pressure high temperature (HPHT) environments.

(a) If you plan to install SSSVs and related equipment in an HPHT environment, you must submit detailed information with your Application for Permit to Drill (APD), Application for Permit to Modify (APM), or Deepwater Operations Plan (DWOP) that demonstrates the SSSVs and related equipment are capable of performing in the applicable HPHT environment. Your detailed information must include the following:

(1) A discussion of the SSSVs' and related equipment's design verification analysis;

(2) A discussion of the SSSVs' and related equipment's design validation and functional testing process and procedures used; and

(3) An explanation of why the analysis, process, and procedures ensure that the SSSVs and related equipment are fit-for-service in the applicable HPHT environment.

(b) For this section, HPHT environment means when one or more of the following well conditions exist:

(1) The completion of the well requires completion equipment or well control equipment assigned a pressure rating greater than 15,000 psig or a temperature rating greater than 350 degrees Fahrenheit;

(2) The maximum anticipated surface pressure or shut-in tubing pressure is greater than 15,000 psig on the seafloor for a well with a subsea wellhead or at the surface for a well with a surface wellhead; or

(3) The flowing temperature is equal to or greater than 350 degrees Fahrenheit on the seafloor for a well with a subsea wellhead or at the surface for a well with a surface wellhead.

(c) For this section, related equipment includes wellheads, tubing heads, tubulars, packers, threaded connections, seals, seal assemblies, production trees, chokes, well control equipment, and any other equipment that will be exposed to the HPHT environment.

§ 250.805 Hydrogen sulfide.

(a) You must conduct production operations in zones known to contain hydrogen sulfide (H_2S) or in zones where the presence of H_2S is unknown, as defined in § 250.490 of this part, in accordance with that section and other relevant requirements of this subpart.

(b) You must receive approval through the DWOP process (§§ 250.286–250.295) for production operations in HPHT environments known to contain H_2S or in HPHT environments where the presence of H_2S is unknown.

§§ 250.806–250.809 [Reserved]

Surface and Subsurface Safety Systems—Dry Trees

§ 250.810 Dry tree subsurface safety devices—general.

For wells using dry trees or for which you intend to install dry trees, you must equip all tubing installations open to hydrocarbon-bearing zones with subsurface safety devices that will shut off the flow from the well in the event of an emergency unless, after you submit a request containing a justification, the District Manager determines the well to be incapable of natural flow. These subsurface safety devices include the following devices and any associated safety valve lock, flow coupling above and below, and landing nipple:

(a) An SSSV, including either:

(1) A surface-controlled SSSV; or

(2) A subsurface-controlled SSSV.

(b) An injection valve.

(c) A tubing plug.

(d) A tubing/annular subsurface safety device.

§ 250.811 Specifications for subsurface safety valves (SSSVs)—dry trees.

All surface-controlled and subsurface-controlled SSSVs, safety valve locks, landing nipples, and flow couplings installed in the OCS must conform to the requirements in §§ 250.801 through 250.803. You may request that BSEE approve non-conforming SSSVs in accordance with § 250.141, regarding alternative procedures or equipment.

§ 250.812 Surface-controlled SSSVs—dry trees.

You must equip all tubing installations open to a hydrocarbon-bearing zone that is capable of natural flow with a surface-controlled SSSV, except as specified in §§ 250.813, 250.815, and 250.816.

(a) The surface controls must be located on the site or at a BSEE-approved remote location. You may request that BSEE approve situating the surface controls at a remote location in accordance with § 250.141, regarding alternative procedures or equipment.

(b) You must equip dry tree wells not previously equipped with a surface-controlled SSSV, and dry tree wells in which a surface-controlled SSSV has been replaced with a subsurface-controlled SSSV with a surface-controlled SSSV when the tubing is first removed and reinstalled.

§ 250.813 Subsurface-controlled SSSVs.

You may request BSEE approval to equip a dry tree well with a subsurface-controlled SSSV in lieu of a surface-controlled SSSV, in accordance with § 250.141 regarding alternative procedures or equipment, if the subsurface-controlled SSSV installed in a well equipped with a surface-controlled SSSV has become inoperable and cannot be repaired without removal and reinstallation of the tubing. If you remove and reinstall the tubing, you must equip the well with a surface-controlled SSSV.

§ 250.814 Design, installation, and operation of SSSVs—dry trees.

You must design, install, operate, repair, and maintain an SSSV to ensure its reliable operation.

(a) You must install the SSSV at a depth at least 100 feet below the mudline within 2 days after production is established. When warranted by conditions such as permafrost, unstable bottom conditions, hydrate formation, or paraffin problems, the District Manager may approve an alternate setting depth in accordance with § 250.141 or § 250.142.

(b) Until the SSSV is installed, the well must be attended in the immediate vicinity so that any necessary emergency actions can be taken while the well is open to flow. During testing and inspection procedures, the well must not be left unattended while open to production unless you have installed a properly operating SSSV in the well.

(c) The well must not be open to flow while the SSSV is removed, except when flowing the well is necessary for a particular operation such as cutting paraffin or performing other routine operations as defined in § 250.601.

(d) You must install, maintain, inspect, repair, and test all SSSVs in accordance with API RP 14B, Recommended Practice for Design, Installation, and Operation of Subsurface Safety Valve Systems (ISO 10417:2004) (incorporated by reference as specified in § 250.198).

§ 250.815 Subsurface safety devices in shut-in wells—dry trees.

(a) You must equip all new dry tree completions (perforated but not placed on production) and completions shut-in for a period of 6 months with one of the following:

(1) A pump-through-type tubing plug;

(2) A surface-controlled SSSV, provided the surface control has been rendered inoperative; or

(3) An injection valve capable of preventing backflow.

(b) When warranted by conditions such as permafrost, unstable bottom conditions, hydrate formation, and paraffin problems the District Manager will approve the setting depth of the subsurface safety device for a shut-in well on a case-by-case basis.

§ 250.816 Subsurface safety devices in injection wells—dry trees.

You must install a surface-controlled SSSV or an injection valve capable of preventing backflow in all injection wells. This requirement is not applicable if the District Manager determines that the well is incapable of natural flow. You must verify the no-flow condition of the well annually.

§ 250.817 Temporary removal of subsurface safety devices for routine operations.

(a) You may remove a wireline- or pumpdown-retrievable subsurface safety device without further authorization or notice, for a routine operation that does not require BSEE approval of a Form BSEE–0124, Application for Permit to Modify (APM). For a list of these routine operations, see § 250.601. The removal period must not exceed 15 days.

(b) You must identify the well by placing a sign on the wellhead stating that the subsurface safety device was removed. You must note the removal of the subsurface safety device in the records required by § 250.890. If the master valve is open, you must ensure that a trained person (see § 250.891) is in the immediate vicinity to attend the well and take any necessary emergency actions.

(c) You must monitor a platform well when a subsurface safety device has been removed, but a person does not need to remain in the well-bay area continuously if the master valve is closed. If the well is on a satellite structure, it must be attended with a support vessel or a pump-through plug installed in the tubing at least 100 feet below the mudline, and the master valve must be closed, unless otherwise approved by the appropriate District Manager.

(d) You must not allow the well to flow while the subsurface safety device is removed, except when it is necessary for the particular operation for which the SSSV is removed. The provisions of this paragraph are not applicable to the testing and inspection procedures specified in § 250.880.

§ 250.818 Additional safety equipment—dry trees.

(a) You must equip all tubing installations that have a wireline- or pumpdown-retrievable subsurface safety device with a landing nipple, with flow couplings or other protective equipment above and below it to provide for the setting of the device.

(b) The control system for all surface-controlled SSSVs must be an integral part of the platform emergency shutdown system (ESD).

(c) In addition to the activation of the ESD by manual action on the platform, the system may be activated by a signal from a remote location. Surface-controlled SSSVs must close in response to shut-in signals from the ESD and in response to the fire loop or other fire detection devices.

§ 250.819 Specification for surface safety valves (SSVs).

All wellhead SSVs and their actuators must conform to the requirements specified in §§ 250.801 through 250.803.

§ 250.820 Use of SSVs.

You must install, maintain, inspect, repair, and test all SSVs in accordance with API RP 14H, Recommended Practice for Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore (incorporated by reference as specified in § 250.198). If any SSV does not operate properly, or if any fluid flow is observed during the leakage test, then you must shut-in all sources to the SSV and repair or replace the valve before resuming production.

§ 250.821 Emergency action.

(a) In the event of an emergency, such as an impending named tropical storm or hurricane:

(1) Any well not yet equipped with a subsurface safety device and that is capable of natural flow must have the subsurface safety device properly installed as soon as possible, with due consideration being given to personnel safety.

(2) You must shut-in all oil wells and gas wells requiring compression, unless otherwise approved by the District Manager in accordance with §§ 250.141 or 250.142. The shut-in may be accomplished by closing the SSV and SSSV.

(b) Closure of the SSV must not exceed 45 seconds after automatic detection of an abnormal condition or actuation of an ESD. The surface-controlled SSSV must close within 2 minutes after the shut-in signal has closed the SSV. The District Manager must approve any design-delayed closure time greater than 2 minutes based on the mechanical/production characteristics of the individual well or subsea field in accordance with §§ 250.141 or 250.142.

§§ 250.822–250.824 [Reserved]

Subsea and Subsurface Safety Systems—Subsea Trees

§ 250.825 Subsea tree subsurface safety devices—general.

(a) For wells using subsea (wet) trees or for which you intend to install subsea trees, you must equip all tubing installations open to hydrocarbon-bearing zones with subsurface safety devices that will shut off the flow from the well in the event of an emergency unless. You may seek BSEE approval for using alternative procedures or equipment in accordance with § 250.141 if you propose to use a subsea safety system that is not capable of shutting off the flow from the well in the event of an emergency, for instance where the well at issue is incapable of natural flow. Subsurface safety devices include the following and any associated safety valve lock, flow coupling above and below, and landing nipple:

(1) A surface-controlled SSSV;

(2) An injection valve;

(3) A tubing plug; and

(4) A tubing/annular subsurface safety device.

(b) After installing the subsea tree, but before the rig or installation vessel leaves the area, you must test all valves and sensors to ensure that they are operating as designed and meet all the conditions specified in this subpart. If you cannot perform these tests, you may seek BSEE approval for a departure from this operating requirement under § 250.142

§ 250.826 Specifications for SSSVs—subsea trees.

All SSSVs, safety valve locks, flow couplings, and landing nipples must conform to the requirements specified in §§ 250.801 through 250.803 and any Deepwater Operations Plan (DWOP) required by §§ 250.286 through 250.295.

§ 250.827 Surface-controlled SSSVs—subsea trees.

All tubing installations open to a hydrocarbon-bearing zone that is capable of natural flow must be equipped with a surface-controlled SSSV, except as specified in §§ 250.829 and 250.830. The surface controls must be located on the site, or you may seek BSEE approval for locating the controls at a remote location in a request to use alternative procedures or equipment under § 250.141.

§ 250.828 Design, installation, and operation of SSSVs—subsea trees.

You must design, install, operate, and maintain an SSSV to ensure its reliable operation.

(a) You must install the SSSV at a depth at least 100 feet below the mudline. When warranted by conditions such as unstable bottom conditions, hydrate formation, or paraffin problems, you may seek BSEE approval for an alternate setting depth in a request to use alternative procedures or equipment under § 250.141.

(b) The well must not be open to flow while an SSSV is inoperable.

(c) You must install, maintain, inspect, repair, and test all SSSVs in accordance with your Deepwater Operations Plan (DWOP) and API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems (ISO 10417:2004) (incorporated by reference as specified in § 250.198).

§ 250.829 Subsurface safety devices in shut-in wells—subsea trees.

(a) You must equip new completions (perforated but not placed on production) and completions shut-in for a period of 6 months with either:

(1) A pump-through-type tubing plug;

(2) An injection valve capable of preventing backflow; or

(3) A surface-controlled SSSV, provided the surface control has been rendered inoperative. For purposes of this section, a surface-controlled SSSV is considered inoperative if for a direct hydraulic control system you have bled the hydraulics from the control line and have isolated it from the hydraulic control pressure or if your controls employ an electro-hydraulic control umbilical and the hydraulic control pressure to the individual well cannot be isolated, and you perform the following:

(i) Disable the control function of the surface-controlled SSSV within the logic of the programmable logic controller which controls the subsea well;

(ii) Place a pressure alarm high on the control line to the surface-controlled SSSV of the subsea well; and

(iii) Close the USV and at least one other tree valve on the subsea well.

(b) The appropriate BSEE District Manager may consider alternate methods on a case-by-case basis.

(c) When warranted by conditions such as unstable bottom conditions, hydrate formations, and paraffin problems, you may seek BSEE approval to use an alternate setting depth of the subsurface safety device for shut-in wells in a request to use alternative procedures or equipment under 250.141.

§ 250.830 Subsurface safety devices in injection wells—subsea trees.

You must install a surface-controlled SSSV or an injection valve capable of preventing backflow in all injection wells. This requirement is not applicable if the District Manager determines that the well is incapable of natural flow. You must verify the no-flow condition of the well annually.

§ 250.831 Alteration or disconnection of subsea pipeline or umbilical

If a necessary alteration or disconnection of the pipeline or umbilical of any subsea well affects your ability to monitor casing pressure or to test any subsea valves or equipment, you must contact the appropriate BSEE District Office at least 48 hours in advance and submit a repair or replacement plan to conduct the required monitoring and testing. You must not alter or disconnect until the repair or replacement plan is approved.

§ 250.832 Additional safety equipment—subsea trees.

(a) You must equip all tubing installations that have a wireline- or pumpdown-retrievable subsurface safety device installed after May 31, 1988, with a landing nipple, with flow couplings, or other protective equipment above and below it to provide for the setting of the SSSV.

(b) The control system for all surface-controlled SSSVs must be an integral part of the platform ESD.

(c) In addition to the activation of the ESD by manual action on the platform, the system may be activated by a signal from a remote location.

§ 250.833 Specification for underwater safety valves (USVs).

All USVs, including those designated as primary or secondary and any alternate isolation valve (AIV) that acts as a USV, if applicable, and their actuators must conform to the requirements specified in §§ 250.801 through 250.803. A production master or wing valve may qualify as a USV under API Spec. 6AV1 (incorporated by reference as specified in § 250.198).

(a) Primary USV (USV1). You must install and designate one USV on a subsea tree as the USV1. The USV1 must be located upstream of the choke valve.

(b) Secondary USV (USV2). You may equip your tree with two or more valves qualified to be designated as a USV, one of which may be designated as USV2. If the USV1 fails to operate properly or exhibits a leakage rate greater than allowed in § 250.880, you must notify the appropriate BSEE District Office and designate the USV2 or another qualified valve (*e.g.,* an AIV) that meets all the requirements of this subpart for USVs as the USV1. This valve must be located upstream of the choke to be designated as a USV.

§ 250.834 Use of USVs.

You must install, maintain, inspect, repair, and test all USVs, including those designated as primary or secondary, and any AIV which acts as a USV if applicable in accordance with this subpart, your DWOP as specified in §§ 250.286 through 250.295, and API RP 14H, Recommended Practice for Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore (incorporated by reference as specified in § 250.198).

§ 250.835 Specification for all boarding shut down valves (BSDVs) associated with subsea systems.

You must install a BSDV on the pipeline boarding riser. All BSDVs and their actuators installed in the OCS must meet the requirements specified in §§ 250.801 through 250.803 and the following requirements. You must:

(a) Ensure that the internal design pressure of the pipeline(s), riser(s), and BSDV(s) is fully rated for the maximum pressure of any input source and comply with the design requirements set forth in Subpart J, unless BSEE approves an alternate design.

(b) Use a BSDV that is fire rated for 30 minutes, and is pressure rated for the maximum allowable operating pressure (MAOP) approved in your pipeline application.

(c) Locate the BSDV within 10 feet of the first point of access to the boarding pipeline riser (*i.e.,* within 10 feet of the edge of platform if the BSDV is horizontal, or within 10 feet above the first accessible working deck, excluding the boat landing and above the splash zone, if the BSDV is vertical).

(d) Install a temperature safety element (TSE) and locate it within 5 feet of each BSDV.

§ 250.836 Use of BSDVs.

All BSDVs must be inspected, maintained, and tested in accordance with API RP 14H, Recommended Practice for Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore (incorporated by reference as specified in § 250.198) for SSVs. If any BSDV does not operate properly or if any fluid flow is observed during the leakage test, then you must shut-in all sources to the BSDV and repair or replace it before resuming production.

§ 250.837 Emergency action and safety system shutdown.

(a) In the event of an emergency, such as an impending named tropical storm or hurricane, you must shut-in all subsea wells unless otherwise approved by the District Manager. A shut-in is defined as a closed BSDV, USV, and surface-controlled SSSV.

(b) When operating a mobile offshore drilling unit (MODU) or other type of workover vessel in an area with producing subsea wells, you must:

(1) Suspend production from all such wells that could be affected by a dropped object, including upstream wells that flow through the same pipeline; or

(2) Establish direct, real-time communications between the MODU and the production facility control room and prepare a plan to be submitted to the appropriate District Manager for approval, as part of an application for a permit to drill or an application for permit to modify, to shut-in any wells that could be affected by a dropped object. If an object is dropped, the driller must immediately secure the well directly under the MODU using the ESD on the well control panel located on the rig floor while simultaneously communicating with the platform to shut-in all affected wells. You must also maintain without disruption and continuously verify communication between the platform and the MODU. If communication is lost between the MODU and the platform for 20 minutes or more, you must shut-in all wells that could be affected by a dropped object.

(c) In the event of an emergency, you must operate your production system according to the valve closure times in the applicable tables in §§ 250.838 and 250.839 for the following conditions:

(1) *Process Upset.* In the event an upset in the production process train occurs downstream of the BSDV, you must close the BSDV in accordance with the applicable tables in §§ 250.838 and 250.839. You may reopen the BSDV to blow down the pipeline to prevent hydrates provided you have secured the well(s) and ensured adequate protection.

(2) *Pipeline pressure safety high and low (PSHL) sensor.* In the event that either a high or a low pressure condition is detected by a PSHL sensor located upstream of the BSDV, you must secure the affected well and pipeline, and all wells and pipelines associated with a dual or multi pipeline system by closing the BSDVs, USVs, and surface-controlled SSSVs in accordance with the applicable tables in §§ 250.838 and 250.839. You must obtain approval from the appropriate BSEE District Manager to resume production in the unaffected pipeline(s) of a dual or multi pipeline system. If the PSHL sensor activation was a false alarm, you may return the wells to production without contacting the appropriate BSEE District Manager.

(3) *ESD/TSE (Platform).* In the event of an ESD activation that is initiated because of a platform ESD or platform TSE on the host platform not associated with the BSDV, you must close the BSDV, USV, and surface-controlled SSSV in accordance with the applicable tables in §§ 250.838 and 250.839.

(4) *Subsea ESD (Platform) or BSDV TSE.* In the event of an emergency shutdown activation that is initiated by the host platform due to an abnormal condition subsea, or a TSE associated with the BSDV, you must close the BSDV, USV, and surface-controlled SSSV in accordance with the applicable tables in §§ 250.838 and 250.839.

(5) *Subsea ESD MODU.* In the event of an ESD activation that is initiated by a MODU because of a dropped object from a rig or intervention vessel, you must secure all wells in the proximity of the MODU by closing the USVs and surface-controlled SSSVs in accordance with the applicable tables in §§ 250.838 and 250.839. You must notify the appropriate BSEE District Manager before resuming production.

(d) You must bleed your low pressure (LP) and high pressure (HP) hydraulic systems in accordance with the applicable tables in §§ 250.838 and 250.839 to ensure that the valves are locked out of service following an ESD or fire and cannot be reopened inadvertently.

§ 250.838 What are the maximum allowable valve closure times and hydraulic bleeding requirements for an electro-hydraulic control system?

(a) If you have an electro-hydraulic control system you must:

(1) Design the subsea control system to meet the valve closure times listed in paragraphs (b) and (d) of this section or your approved DWOP; and

(2) Verify the valve closure times upon installation. The BSEE District Manager may require you to verify the closure time of the USV(s) through visual authentication by diver or ROV.

(b) If you have not lost communication with your rig or platform, you must comply with the maximum allowable valve closure times and hydraulic system bleeding requirements listed in the following table or your approved DWOP:

VALVE CLOSURE TIMING, ELECTRO-HYDRAULIC CONTROL SYSTEM

If you have the following . . .	Your pipeline BSDV must . . .	Your USV1 must . . .	Your USV2 must . . .	Your alternate isolation valve must . . .	Your surface-controlled SSSV must . . .	Your LP hydraulic system must . . .	Your HP hydraulic system must . . .
(1) Process upset.	Close within 45 seconds after sensor activation.	[no requirements]			[no requirements] ...	[no requirements] ...	[no requirements]
(2) Pipeline PSHL.	Close within 45 seconds after sensor activation.	Close one or more valves within 2 minute and 45 seconds after sensor activation. Close the designated USV1 within 20 minutes after sensor activation			Close within 60 minutes after sensor activation. If you use a 60-minute resettable timer, you may continue to reset the time for closure up to a maximum of 24 hours total.	[no requirements] ...	Initiate unrestricted bleed within 24 hours after sensor activation.
(3) ESD/TSE (Platform).	Close within 45 seconds after ESD or sensor activation.	Close within 5 minutes after ESD or sensor activation. If you use a 5-minute resettable timer, you may continue to reset the time for closure up to a maximum of 20 minutes total.		Close within 20 minutes after ESD or sensor activation.	Close within 20 minutes after ESD or sensor activation. If you use a 20-minute resettable timer, you may continue to reset the time for closure up to a maximum of 60 minutes total.	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation. If you use a 60-minute resettable timer you must initiate unrestricted bleed within 24 hours.	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation. If you use a 60-minute resettable timer you must initiate unrestricted bleed within 24 hours.
(4) Subsea ESD (Platform) or BSDV TSE.	Close within 45 seconds after ESD or sensor activation.	Close one or more valves within 2 minutes and 45 seconds after ESD or sensor activation. Close all tree valves within 10 minutes after ESD or sensor activation.			Close within 10 minutes after ESD or sensor activation.	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation.	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation.
(5) Dropped object—(Subsea ESD MODU).	[no requirements].	Initiate valve closure immediately. You may allow for closure of the tree valves immediately prior to closure of the surface-controlled SSSV if desired.				Initiate unrestricted bleed immediately.	Initiate unrestricted bleed within 10 minutes after ESD activation.

(c) If you have an electro-hydraulic control system and experience a loss of communications (EH Loss of Comms), you must comply with the following:

(1) If you can meet the EH Loss of Comms valve closure timing conditions specified in the table in this section, you must notify the appropriate BSEE District Office within 12 hours of detecting the loss of communication.

(2) If you cannot meet the EH Loss of Comms valve closure timing conditions specified in the table in this section, you must notify the appropriate BSEE District Office immediately after detecting the loss of communication. You must shut-in production by initiating a bleed of the low pressure (LP) hydraulic system or the high pressure (HP) hydraulic system within 120 minutes after loss of communication. Bleed the other hydraulic system within 180 minutes after loss of communication.

(3) You must obtain prior approval from the appropriate BSEE District Manager if you want to continue to produce after loss of communication when you cannot meet the EH Loss of Comms valve closure times specified in the table in paragraph (d) of this section. In your request, include an alternate valve closure table that your system is able to achieve. The appropriate BSEE District Manager may also approve an alternate hydraulic bleed schedule to allow for hydrate mitigation and orderly shut-in.

(d) If you experience a loss of communications, you must comply with the maximum allowable valve closure times and hydraulic system bleeding requirements listed in the following table or your approved DWOP:

VALVE CLOSURE TIMING, ELECTRO-HYDRAULIC CONTROL SYSTEM WITH LOSS OF COMMUNICATION

If you have the following . . .	Your pipeline BSDV must . . .	Your USV1 must . . .	Your USV2 must . . .	Your alternate isolation valve must . . .	Your surface-controlled SSSV must . . .	Your LP hydraulic system must . . .	Your HP hydraulic system must . . .
(1) Process upset.	Close within 45 seconds after sensor activation.	[no requirements]			[no requirements] ...	[no requirements] ...	[no requirements].

VALVE CLOSURE TIMING, ELECTRO-HYDRAULIC CONTROL SYSTEM WITH LOSS OF COMMUNICATION—Continued

If you have the following . . .	Your pipeline BSDV must . . .	Your USV1 must . . .	Your USV2 must . . .	Your alternate isolation valve must . . .	Your surface-controlled SSSV must . . .	Your LP hydraulic system must . . .	Your HP hydraulic system must . . .
(2) Pipeline PSHL.	Close within 45 seconds after sensor activation.	Initiate closure when LP hydraulic system is bled (close valves within 5 minutes after sensor activation).			Initiate closure when HP hydraulic system is bled (close within 24 hours after sensor activation).	Initiate unrestricted bleed immediately, concurrent with sensor activation.	Initiate unrestricted bleed within 24 hours after sensor activation.
(3) ESD/TSE (Platform).	Close within 45 seconds after ESD or sensor activation.	Initiate closure when LP hydraulic system is bled (close valves within 20 minutes after ESD or sensor activation).			Initiate closure when HP hydraulic system is bled (close within 60 minutes after ESD or sensor activation).	Initiate unrestricted bleed concurrent with BSDV closure (bleed within 20 minutes after ESD or sensor activation).	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation.
(4) Subsea ESD (Platform) or BSDV TSE.	Close within 45 seconds after ESD or sensor activation.	Initiate closure when LP hydraulic system is bled (close valves within 5 minutes after ESD or sensor activation).			Initiate closure when HP hydraulic system is bled (close within 20 minutes after ESD or sensor activation).	Initiate unrestricted bleed immediately.	Initiate unrestricted bleed immediately, allowing for surface-controlled SSSV closure within 20 minutes.
(5) Dropped object—subsea ESD (MODU).	[no requirements].	Initiate closure immediately. You may allow for closure of the tree valves immediately prior to closure of the surface-controlled SSSV if desired.				Initiate unrestricted bleed immediately.	Initiate unrestricted bleed immediately

§ 250.839 What are the maximum allowable valve closure times and hydraulic bleeding requirements for direct-hydraulic control system?

(a) If you have direct-hydraulic control system you must:

(1) Design the subsea control system to meet the valve closure times listed in this section or your approved DWOP; and

(2) Verify the valve closure times upon installation. The BSEE District Manager may require you to verify the closure time of the USV(s) through visual authentication by diver or ROV.

(b) You must comply with the maximum allowable valve closure times and hydraulic system bleeding requirements listed in the following table or your approved DWOP:

VALVE CLOSURE TIMING, DIRECT-HYDRAULIC CONTROL SYSTEM

If you have the following . . .	Your pipeline BSDV must . . .	Your USV1 must . . .	Your USV2 must . . .	Your alternate isolation valve must . . .	Your surface-controlled SSSV must . . .	Your LP hydraulic system must . . .	Your HP hydraulic system must . . .
(1) Process upset.	Close within 45 seconds after sensor activation.	[no requirements]			[no requirements] ...	[no requirements] ...	[no requirements].
(2) Flowline PSHL.	Close within 45 seconds after sensor activation.	Close one or more valves within 2 minutes and 45 seconds after sensor activation. Close the designated USV1 within 20 minutes after sensor activation.			Close within 24 hours after sensor activation.	Complete bleed of USV1, USV2 and the AIV within 20 minutes after sensor activation.	Complete bleed within 24 hours after sensor activation.
(3) ESD/TSE (Platform).	Close within 45 seconds after ESD or sensor activation.	Close all valves within 20 minutes after ESD or sensor activation.			Close within 60 minutes after ESD or sensor activation.	Complete bleed of USV1, USV2 and the AIV within 20 minutes after ESD or sensor activation.	Complete bleed within 60 minutes after ESD or sensor activation.
(4) Subsea ESD (Platform) or BSDV TSE.	Close within 45 seconds after ESD or sensor activation.	Close one or more valves within 2 minutes and 45 seconds after ESD or sensor activation. Close all tree valves within 10 minutes after ESD or sensor activation.			Close within 10 minutes after ESD or sensor activation.	Complete bleed of USV1, USV2, and the AIV within 10 minutes after ESD or sensor activation.	Complete bleed within 10 minutes after ESD or sensor activation.
(5) Dropped object—Subsea ESD. (MODU)	[no requirements].	Initiate closure immediately. If desired, you may allow for closure of the tree valves immediately prior to closure of the surface-controlled SSSV.				Initiate unrestricted bleed immediately.	Initiate unrestricted bleed immediately.

Production Safety Systems

§ 250.840 Design, installation, and maintenance—general.

You must design, install, and maintain all production facilities and equipment including, but not limited to, separators, treaters, pumps, heat exchangers, fired components, wellhead injection lines, compressors, headers, and flowlines in a manner that is efficient, safe, and protects the environment.

§ 250.841 Platforms.

(a) You must protect all platform production facilities 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, Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms (incorporated by reference as specified in § 250.198). If you use processing components other than those for which Safety Analysis Checklists are included in API RP 14C, you must utilize the analysis technique and documentation specified in API RP 14C to determine the effects and requirements of these components on the safety system. Safety device requirements for pipelines are contained in 30 CFR 250.1004.

(b) You must design, analyze, install, test, and maintain in operating condition all platform production process piping in accordance with API RP 14E, Design and Installation of Offshore Production Platform Piping Systems and API 570, Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems (both incorporated by reference as specified in § 250.198). The District Manager may approve temporary repairs to facility piping on a case-by-case basis for a period not to exceed 30 days.

§ 250.842 Approval of safety systems design and installation features.

(a) Before you install or modify a production safety system, you must submit a production safety system application to the District Manager for approval. The application must include the information prescribed in the following table:

You must submit:	Details and/or additional requirements:
(1) A schematic piping and instrumentation diagram . . .	Showing the following: (i) Well shut-in tubing pressure; (ii) Piping specification breaks, piping sizes; (iii) Pressure relief valve set points; (iv) Size, capacity, and design working pressures of separators, flare scrubbers, heat exchangers, treaters, storage tanks, compressors and metering devices; (v) Size, capacity, design working pressures, and maximum discharge pressure of hydrocarbon-handling pumps; (vi) size, capacity, and design working pressures of hydrocarbon-handling vessels, and chemical injection systems handling a material having a flash point below 100 degrees Fahrenheit for a Class I flammable liquid as described in API RP 500 and 505 (both incorporated by reference as specified in § 250.198). (vii) Size and maximum allowable working pressures as determined in accordance with API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems (incorporated by reference as specified in § 250.198).
(2) A safety analysis flow diagram (API RP 14C, Appendix E) and the related Safety Analysis Function Evaluation (SAFE) chart (API RP 14C, subsection 4.3.3) (incorporated by reference as specified in § 250.198)	If processing components are used, other than those for which Safety Analysis Checklists are included in API RP 14C, you must use the same analysis technique and documentation to determine the effects and requirements of these components upon the safety system.
(3) Electrical system information, including	(i) A plan for each platform deck and outlining all classified areas. You must classify 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; or API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2 (both incorporated by reference as specified in § 250.198). (ii) Identification of all areas where potential ignition sources, including non-electrical ignition sources, are to be installed showing: (A) All major production equipment, wells, and other significant hydrocarbon sources, and a description of the type of decking, ceiling, and walls (*e.g.,* grating or solid) and firewalls and; (B) the location of generators, control rooms, panel boards, major cabling/conduit routes, and identification of the primary wiring method (*e.g.,* type cable, conduit, wire) and; (iii) one-line electrical drawings of all electrical systems including the safety shutdown system. You must also include a functional legend.
(4) Schematics of the fire and gas-detection systems	Showing a functional block diagram of the detection system, including the electrical power supply and also including the type, location, and number of detection sensors; the type and kind of alarms, including emergency equipment to be activated; the method used for detection; and the method and frequency of calibration.
(5) The service fee listed in § 250.125	The fee you must pay will be determined by the number of components involved in the review and approval process.

(b) The production safety system application must also include the following certifications:

(1) That all electrical installations were designed according to API RP 14F, Design, Installation, and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Division 1 and Division 2 Locations, or API RP 14FZ, Recommended Practice for Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Zone 0, Zone 1 and Zone 2 Locations, as applicable (incorporated by reference as specified in § 250.198);

(2) That the designs for the mechanical and electrical systems were reviewed, approved, and stamped by a registered professional engineer(s). The registered professional engineer must be registered in a State or Territory in the United States and have sufficient expertise and experience to perform the duties; and

(3) That a hazard analysis was performed during the design process in accordance with API RP 14J (incorporated by reference as specified in § 250.198), and that you have a hazards analysis program in place to assess potential hazards during the operation of the platform:

(c) Before you begin production, you must certify, in a letter to the District Manager, that the mechanical and electrical systems were installed in accordance with the approved designs.

(d) Within 60 days after production, you must certify, in a letter to the District Manager, that the as-built diagrams outlined in (a)(1) and (2) of this section and the piping and instrumentation diagrams are on file and have been certified correct and stamped by a registered professional engineer(s). The registered professional engineer must be registered in a State or Territory in the United States and have sufficient expertise and experience to perform the duties.

(e) All as-built diagrams outlined in (a)(1) and (2) of this section must be submitted to the District Manager within 60 days after production.

(f) You must maintain information concerning the approved design and installation features of the production safety system at your offshore field office nearest the OCS facility or at other locations conveniently available to the District Manager. As-built piping and instrumentation diagrams must be maintained at a secure onshore location and readily available offshore. These documents must be made available to BSEE upon request and be retained for the life of the facility. All approvals are subject to field verifications.

§§ 250.843—250.849 [Reserved]

Additional Production System Requirements

§ 250.850 Production system requirements—general.

You must comply with the production safety system requirements in the following sections (§§ 250.851 through 250.872), some of which are in addition to those contained in API RP 14C (incorporated by reference as specified in § 250.198).

§ 250.851 Pressure vessels (including heat exchangers) and fired vessels.

(a) Pressure vessels (including heat exchangers) and fired vessels must meet the requirements in the following table:

Item name	Applicable codes and requirements
(1) Pressure and fired vessels where the operating pressure is or will be 15 pounds per square inch gauge (psig) or greater.	(i) Must be designed, fabricated, and code stamped according to applicable provisions of sections I, IV, and VIII of the ANSI/ASME Boiler and Pressure Vessel Code. (ii) Must be repaired, maintained, and inspected in accordance with API 510, Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration, Downstream Segment (incorporated by reference as specified in § 250.198).
(2) Pressure and fired vessels (such as flare and vent scrubbers) where the operating pressure is or will be at least 5 psig and less than 15 psig.	Must employ a safety analysis checklist in the design of each component. These vessels do not need to be ASME Code stamped as pressure vessels.
(3) Pressure and fired vessels where the operating pressure is or will be less than 5 psig.	Are not subject to the requirements of paragraphs (a)(1) and (a)(2).
(4) Existing uncoded Pressure and fired vessels (i) in use on the effective date of the final rule; (ii) with an operating pressure of 5 psig or greater; and (iii) that are not code stamped in accordance with the ANSI/ASME Boiler and Pressure Vessel Code . . .	Must be justified and approval obtained from the District Manager for their continued use beyond 18 months from the effective date of the final rule.
(5) Pressure relief valves	(i) Must be designed and installed according to applicable provisions of sections I, IV, and VIII of the ASME Boiler and Pressure Vessel Code. (ii) Must conform to the valve sizing and pressure-relieving requirements specified in these documents, but (except for completely redundant relief valves), must be set no higher than the maximum-allowable working pressure of the vessel. (iii) And vents must be positioned in such a way as to prevent fluid from striking personnel or ignition sources.
(6) Steam generators operating at less than 15 psig	Must be equipped with a level safety low (LSL) sensor which will shut off the fuel supply when the water level drops below the minimum safe level.
(7) Steam generators operating at 15 psig or greater	(i) Must be equipped with a level safety low (LSL) sensor which will shut off the fuel supply when the water level drops below the minimum safe level. (ii) You must also install a water-feeding device that will automatically control the water level except when closed loop systems are used for steam generation.

(b) *Operating pressure ranges.* You must use pressure recording devices to establish the new operating pressure ranges of pressure vessels at any time the normalized system pressure changes by 5 percent. You must maintain the pressure recording information you used to determine current operating pressure ranges at your field office nearest the OCS facility or at another location conveniently available to the District Manager for as long as the information is valid.

(c) Pressure shut-in sensors must be set according to the following table:

Type of sensor	Settings	Additional requirements
(1) High pressure shut-in sensor.	Must be no higher than 15 percent or 5 psi (whichever is greater) above the highest operating pressure of the vessel.	Must also be set sufficiently below (5 percent or 5 psi, whichever is greater) the relief valve's set pressure to assure that the pressure source is shut-in before the relief valve activates.
(2) Low pressure shut-in sensor.	Must be set no lower than 15 percent or 5 psi (whichever is greater) below the lowest pressure in the operating range.	You must receive specific approval from the District Manager for activation limits on pressure vessels that have a pressure safety low (PSL) sensor set less than 5 psi.

§ 250.852 Flowlines/Headers.

(a)(1) You must equip flowlines from wells with both PSH and PSL sensors. You must locate these sensors in accordance with section A.1 of API RP 14C (incorporated by reference as specified in § 250.198).

(2) You must use pressure recording devices to establish the new operating pressure ranges of flowlines at any time when the normalized system pressure changes by 50 psig or 5 percent, whichever is higher.

(3) You must maintain the most recent pressure recording information you used to determine operating pressure ranges at your field office nearest the OCS facility or at another location conveniently available to the District Manager for as long as the information is valid.

(b) Flowline shut-in sensors must meet the requirements in the following table:

Type of flowline sensor	Settings
(1) PSH sensor	Must be set no higher than 15 percent or 5 psi (whichever is greater) above the highest operating pressure of the flowline. In all cases, the PSH must be set sufficiently below the maximum shut-in wellhead pressure or the gas-lift supply pressure to assure actuation of the SSV. Do not set the PSH sensor above the maximum allowable working pressure of the flowline.
(2) PSL sensor	Must be set no lower than 15 percent or 5 psi (whichever is greater) below the lowest operating pressure of the flowline in which it is installed.

(c) If a well flows directly to a pipeline before separation, the flowline and valves from the well located upstream of and including the header inlet valve(s) must have a working pressure equal to or greater than the maximum shut-in pressure of the well unless the flowline is protected by one of the following:

(1) A relief valve which vents into the platform flare scrubber or some other location approved by the District Manager. You must design the platform flare scrubber to handle, without liquid-hydrocarbon carryover to the flare, the maximum-anticipated flow of liquid hydrocarbons that may be relieved to the vessel; or

(2) Two SSVs with independent PSH sensors connected to separate relays and sensing points and installed with adequate volume upstream of any block valve to allow sufficient time for the SSVs to close before exceeding the maximum allowable working pressure. Each independent PSH sensor must close both SSVs along with any associated flowline PSL sensor. If the maximum shut-in pressure of a dry tree satellite well(s) is greater than 1½ times the maximum allowable pressure of pipeline, a pressure safety valve (PSV) of sufficient size and relief capacity to protect against any SSV leakage or fluid hammer effect may be required by the District Manager. The PSV must be installed upstream of the host platform boarding valve and vent into the platform flare scrubber or some other location approved by the District Manager.

(d) If a well flows directly to the pipeline from a header without prior separation, the header, the header inlet valves, and pipeline isolation valve must have a working pressure equal to or greater than the maximum shut-in pressure of the well unless the header is protected by the safety devices as outlined in paragraph (c) of this section.

(e) If you are installing flowlines constructed of unbonded flexible pipe on a floating platform, you must:

(1) Review the manufacturer's Design Methodology Verification Report and the independent verification agent's (IVA's) certificate for the design methodology contained in that report to ensure that the manufacturer has complied with the requirements of API Spec. 17J, Specification for Unbonded Flexible Pipe (ISO 13628–2:2006) (incorporated by reference as specified in § 250.198);

(2) Determine that the unbonded flexible pipe is suitable for its intended purpose;

(3) Submit to the District Manager the manufacturer's design specifications for the unbonded flexible pipe; and

(4) Submit to the District Manager a statement certifying that the pipe is suitable for its intended use and that the manufacturer has complied with the IVA requirements of API Spec. 17J (ISO 13628–2:2006) (incorporated by reference as specified in § 250.198).

(f) Automatic pressure or flow regulating choking devices must not prevent the normal functionality of the process safety system that includes, but is not limited to, the flowline pressure safety devices and the SSV.

(g) You may install a single flow safety valve (FSV) on the platform to protect multiple subsea pipelines or wells that tie into a single pipeline riser provided that you install an FSV for each riser and test it in accordance with the criteria prescribed in § 250.880(c)(2)(v).

(h) You may install a single PSHL sensor on the platform to protect multiple subsea pipelines that tie into a single pipeline riser provided that you install a PSHL sensor for each riser and locate it upstream of the BSDV.

§ 250.853 Safety sensors.

You must ensure that:

(a) All shutdown devices, valves, and pressure sensors function in a manual reset mode;

(b) Sensors with integral automatic reset are equipped with an appropriate device to override the automatic reset mode;

(c) All pressure sensors are equipped to permit testing with an external pressure source; and,

(d) All level sensors are equipped to permit testing through an external bridle on all new vessel installations.

§ 250.854 Floating production units equipped with turrets and turret mounted systems.

(a) For floating production units equipped with an auto slew system, you must integrate the auto slew control system with your process safety system allowing for automatic shut-in of the production process, including the sources (subsea wells, subsea pumps, *etc.*) and releasing of the buoy. Your safety system must immediately initiate a process system shut-in according to §§ 250.838 and 250.839 and release the buoy to prevent hydrocarbon discharge and damage to the subsea infrastructure when the following are encountered:

(i) Your buoy is clamped,

(ii) Your auto slew mode is activated, and

(iii) You encounter a ship heading/position failure or an exceedance of the rotational tolerances of the clamped buoy.

(b) For floating production units equipped with swivel stack arrangements, you must equip the portion of the swivel stack containing hydrocarbons with a leak detection system. Your leak detection system must be tied into your production process surface safety system allowing for automatic shut-in of the system. Upon seal system failure and detection of a hydrocarbon leak, your surface safety system must immediately initiate a process system shut-in according to §§ 250.838 and 250.839.

§ 250.855 Emergency shutdown (ESD) system.

The ESD system must conform to the requirements of Appendix C, section C1, of API RP 14C (incorporated by reference as specified in § 250.198), and the following:

(a) The manually operated ESD valve(s) must be quick-opening and nonrestricted to enable the rapid actuation of the shutdown system. Only ESD stations at the boat landing may utilize a loop of breakable synthetic tubing in lieu of a valve. This breakable loop is not required to be physically located on the boat landing, but must be accessible from a boat.

(b) You must maintain a schematic of the ESD that indicates the control functions of all safety devices for the platforms on the platform, at your field office nearest the OCS facility, or at another location conveniently available to the District Manager for the life of the facility.

§ 250.856 Engines.

(a) *Engine exhaust.* You must equip all engine exhausts to comply with the insulation and personnel protection requirements of API RP 14C, section 4.2., (incorporated by reference as specified in § 250.198). You must equip exhaust piping from diesel engines with spark arresters.

(b) *Diesel engine air intake.* You must equip diesel engine air intakes with a device to shutdown the diesel engine in the event of runaway. You must equip diesel engines that are continuously attended with either remotely operated manual or automatic shutdown devices. You must equip diesel engines that are not continuously attended with automatic shutdown devices. The following diesel engines do not require a shutdown device: Engines for fire water pumps; engines on emergency generators; engines that power BOP accumulator systems; engines that power air supply for confined entry personnel; temporary equipment on non-producing platforms; booster engines whose purpose is to start larger engines; and engines that power portable single cylinder rig washers.

§ 250.857 Glycol dehydration units.

(a) You must install a pressure relief system or an adequate vent on the glycol regenerator (reboiler) to prevent overpressurization. The discharge of the relief valve must be vented in a nonhazardous manner.

(b) You must install the FSV on the dry glycol inlet to the glycol contact tower as near as practical to the glycol contact tower.

(c) You must install the shutdown valve (SDV) on the wet glycol outlet from the glycol contact tower as near as practical to the glycol contact tower.

250.858 Gas compressors.

(a) You must equip compressor installations with the following protective equipment as required in API RP 14C, sections A4 and A8 (incorporated by reference as specified in § 250.198).

(1) A pressure safety high (PSH) sensor, a pressure safety low (PSL) sensor, a pressure safety valve (PSV), and a level safety high (LSH) sensor, and a level safety low (LSL) sensor to protect each interstage and suction scrubber.

(2) A temperature safety high (TSH) sensor on each compressor discharge cylinder.

(3) You must design the PSH and PSL sensors and LSH controls protecting compressor suction and interstage scrubbers to actuate automatic SDVs located in each compressor suction and fuel gas line so that the compressor unit and the associated vessels can be isolated from all input sources. All automatic SDVs installed in compressor suction and fuel gas piping must also be actuated by the shutdown of the prime mover. Unless otherwise approved by the District Manager, gas-well gas affected by the closure of the automatic SDV on a compressor suction must be diverted to the pipeline or shut-in at the wellhead.

(4) You must install a blowdown valve on the discharge line of all compressor installations that are 1,000 horsepower (746 kilowatts) or greater.

(b) You must use pressure recording devices to establish the new operating pressure ranges for compressor discharge sensors at any time when the normalized system pressure changes by 50 psig or 5 percent, whichever is higher. You must:

(1) Maintain the most recent pressure recording information that you used to determine operating pressure ranges at your field office nearest the OCS facility or at another location conveniently available to the District Manager.

(2) Set the PSH sensor(s) no higher than 15 percent or 5 psi, whichever is greater, above the highest operating pressure of the discharge line and sufficiently below the maximum discharge pressure to ensure actuation of the suction SDV. Set the PSH sensor(s) sufficiently below (5 percent or 5 psi, whichever is greater) the set pressure of the PSV to assure that the pressure source is shut-in before the PSV activates.

(3) Set PSL sensor(s) no lower than 15 percent or 5 psi, whichever is greater, below the lowest operating pressure of the discharge line in which it is installed.

(c) For vapor recovery units, when the suction side of the compressor is operating below 5 psig and the system is capable of being vented to atmosphere, you are not required to install PSH and PSL sensors on the suction side of the compressor.

§ 250.859 Firefighting systems.

(a) Firefighting systems for both open and totally enclosed platforms installed for extreme weather conditions or other reasons must conform to API RP 14G, Recommended Practice for Fire Prevention and Control on Fixed Open-type Offshore Production Platforms (incorporated by reference as specified in § 250.198), and require approval of the District Manager. The following additional requirements apply for both open- and closed-production platforms:

(1) You must install a firewater system consisting of rigid pipe with firehose stations fixed firewater monitors. The firewater system must protect in all areas where production-handling equipment is located. You

must install a fixed water spray system in enclosed well-bay areas where hydrocarbon vapors may accumulate.

(2) Fuel or power for firewater pump drivers must be available for at least 30 minutes of run time during a platform shut-in. If necessary, you must install an alternate fuel or power supply to provide for this pump operating time unless the District Manager has approved an alternate firefighting system. As of 1 year after the publication date of the final rule, you must have equipped all new firewater pump drivers with automatic starting capabilities upon activation of the ESD, fusible loop, or other fire detection system. For electric driven firewater pump drivers, in the event of a loss of primary power, you must install an automatic transfer switch to cross over to an emergency power source in order to maintain at least 30 minutes of run time. The emergency power source must be reliable and have adequate capacity to carry the locked-rotor currents of the fire pump motor and accessory equipment. You must route power cables or conduits with wires installed between the fire water pump drivers and the automatic transfer switch away from hazardous-classified locations that can cause flame impingement. Power cables or conduits with wires that connect to the fire water pump drivers must be capable of maintaining circuit integrity for not less than 30 minutes of flame impingement.

(3) You must post a diagram of the firefighting system showing the location of all firefighting equipment in a prominent place on the facility or structure.

(4) For operations in subfreezing climates, you must furnish evidence to the District Manager that the firefighting system is suitable for those conditions.

(5) All firefighting equipment located on a facility must be in good working order whether approved as the primary, secondary, or ancillary firefighting system.

(b) *Inoperable Firewater Systems.* If you are required to maintain a firewater system and it becomes inoperable, either shut-in your production operations while making the necessary repairs, or request that the appropriate BSEE District Manager grant you a departure under § 250.142 to use a firefighting system using chemicals on a temporary basis (for a period up to 7 days) while you make the necessary repairs. If you are unable to complete repairs during the approved time period because of circumstances beyond your control, the BSEE District Manager may grant extensions to your approved departure for periods up to 7 days.

§ 250.860 Chemical firefighting system.

(a) *Major platforms and minor manned platforms.* A firefighting system using chemicals-only may be used in lieu of a water-based system on a major platform or a minor manned platform if the District Manager determines that the use of a chemical system provides equivalent fire-protection control and would not increase the risk to human safety. A major platform is a structure with either six or more completions or zero to five completions with more than one item of production process equipment. A minor platform is a structure with zero to five completions with one item of production process equipment. A manned platform is one that is attended 24 hours a day or one on which personnel are quartered overnight. To obtain approval to use a chemical-only fire prevention and control system on a major platform or a minor manned platform, in lieu of a water system, you must submit to the District Manager:

(1) A justification for asserting that the use of a chemical system provides equivalent fire-protection control. The justification must address fire prevention, fire protection, fire control, and firefighting on the platform; and

(2) A risk assessment demonstrating that a chemical-only system would not increase the risk to human safety. Provide the following and any other important information in your risk assessment:

For the use of a chemical firefighting system on major and minor manned platforms, you must provide the following in your risk assessment . . .	Including . . .
(i) Platform description	(A) The type and quantity of hydrocarbons (*i.e.,* natural gas, oil) that are produced, handled, stored, or processed at the facility.
	(B) The capacity of any tanks on the facility that you use to store either liquid hydrocarbons or other flammable liquids.
	(C) The total volume of flammable liquids (other than produced hydrocarbons) stored on the facility in containers other than bulk storage tanks. Include flammable liquids stored in paint lockers, storerooms, and drums.
	(D) If the facility is manned, provide the maximum number of personnel on board and the anticipated length of their stay.
	(E) If the facility is unmanned, provide the number of days per week the facility will be visited, the average length of time spent on the facility per day, the mode of transportation, and whether or not transportation will be available at the facility while personnel are on board.
	(F) A diagram that depicts: Quarters location, production equipment location, fire prevention and control equipment location, lifesaving appliances and equipment location, and evacuation plan escape routes from quarters and all manned working spaces to primary evacuation equipment.
(ii) Hazard assessment (facility specific).	(A) Identification of all likely fire initiation scenarios (including those resulting from maintenance and repair activities). For each scenario, discuss its potential severity and identify the ignition and fuel sources.
	(B) Estimates of the fire/radiant heat exposure that personnel could be subjected to. Show how you have considered designated muster areas and evacuation routes near fuel sources and have verified proper flare boom sizing for radiant heat exposure.
(iii) Human factors assessment (not facility specific).	(A) Descriptions of the fire-related training your employees and contractors have received. Include details on the length of training, whether the training was hands-on or classroom, the training frequency, and the topics covered during the training.
	(B) Descriptions of the training your employees and contractors have received in fire prevention, control of ignition sources, and control of fuel sources when the facility is occupied.
	(C) Descriptions of the instructions and procedures you have given to your employees and contractors on the actions they should take if a fire occurs. Include those instructions and procedures specific to evacuation. State how you convey this information to your employees and contractor on the platform.

For the use of a chemical firefighting system on major and minor manned platforms, you must provide the following in your risk assessment . . .	Including . . .
(iv) Evacuation assessment (facility specific).	(A) A general discussion of your evacuation plan. Identify your muster areas (if applicable), both the primary and secondary evacuation routes, and the means of evacuation for both. (B) Description of the type, quantity, and location of lifesaving appliances available on the facility. Show how you have ensured that lifesaving appliances are located in the near vicinity of the escape routes. (C) Description of the types and availability of support vessels, whether the support vessels are equipped with a fire monitor, and the time needed for support vessels to arrive at the facility. (D) Estimates of the worst case time needed for personnel to evacuate the facility should a fire occur.
(v) Alternative protection assessment.	(A) Discussion of the reasons you are proposing to use an alternative fire prevention and control system. (B) Lists of the specific standards used to design the system, locate the equipment, and operate the equipment/system. (C) Description of the proposed alternative fire prevention and control system/equipment. Provide details on the type, size, number, and location of the prevention and control equipment. (D) Description of the testing, inspection, and maintenance program you will use to maintain the fire prevention and control equipment in an operable condition. Provide specifics regarding the type of inspection, the personnel who conduct the inspections, the inspection procedures, and documentation and recordkeeping.
(vi) Conclusion	A summary of your technical evaluation showing that the alternative system provides an equivalent level of personnel protection for the specific hazards located on the facility.

(b) *Changes after approval.* If BSEE has approved your request to use a chemical-only fire suppressant system in lieu of a water system, and if you make an insignificant change to your platform subsequent to that approval, document the change and maintain the documentation at the facility or nearest field office for BSEE review and/or inspection and maintain for the life of the facility. Do not submit this documentation to the BSEE District Manager. However, if you make a significant change to your platform (*e.g.,* placing a storage vessel with a capacity of 100 barrels or more on the facility, adding production equipment) or if you plan to man an unmanned platform temporarily, submit a new request, including an updated risk assessment, to the appropriate BSEE District Manager for approval. You must maintain the most recent documentation that you submitted to BSEE for the life of the facility at either location discussed previously.

(c) *Minor unmanned platforms.* You may use a U.S. Coast Guard type and size rating ''B–II'' portable dry chemical unit (with a minimum UL Rating (US) of 60–B:C) or a 30-pound portable dry chemical unit, in lieu of a water system, on all platforms that are both minor and unmanned, as long as you ensure that the unit is available on the platform when personnel are on board.

§ 250.861 Foam firefighting system.

When foam firefighting systems are installed as part of your firefighting system, you must:

(a) Annually conduct an inspection of the foam concentrates and their tanks or storage containers for evidence of excessive sludging or deterioration.

(b) Annually send samples of the foam concentrate to the manufacturer or authorized representative for quality condition testing. You must have the sample tested to determine the specific gravity, pH, percentage of water dilution, and solid content. Based on these results, the foam must be certified by an authorized representative of the manufacturer as suitable firefighting foam per the original manufacturer's specifications. The certification document must be readily accessible for field inspection. In lieu of sampling and certification, you may choose to replace the total inventory of foam with suitable new stock.

(c) The quantity of concentrate must meet design requirements, and tanks or containers must be kept full with space allowed for expansion.

§ 250.862 Fire and gas-detection systems.

(a) You must install fire (flame, heat, or smoke) sensors in all enclosed classified areas. You must install gas sensors in all inadequately ventilated, enclosed classified areas. Adequate ventilation is defined as ventilation that is sufficient to prevent accumulation of significant quantities of vapor-air mixture in concentrations over 25 percent of the lower explosive limit. An acceptable method of providing adequate ventilation is one that provides a change of air volume each 5 minutes or 1 cubic foot of air-volume flow per minute per square foot of solid floor area, whichever is greater. Enclosed areas (*e.g.,* buildings, living quarters, or doghouses) are defined as those areas confined on more than four of their six possible sides by walls, floors, or ceilings more restrictive to air flow than grating or fixed open louvers and of sufficient size to allow entry of personnel. A classified area is any area classified Class I, Group D, Division 1 or 2, following the guidelines of API RP 500 (incorporated by reference as specified in § 250.198), or any area classified Class I, Zone 0, Zone 1, or Zone 2, following the guidelines of API RP 505 (incorporated by reference as specified in § 250.198).

(b) All detection systems must be capable of continuous monitoring. Fire-detection systems and portions of combustible gas-detection systems related to the higher gas concentration levels must be of the manual-reset type. Combustible gas-detection systems related to the lower gas-concentration level may be of the automatic-reset type.

(c) A fuel-gas odorant or an automatic gas-detection and alarm system is required in enclosed, continuously manned areas of the facility which are provided with fuel gas. Living quarters and doghouses not containing a gas source and not located in a classified area do not require a gas detection system.

(d) The District Manager may require the installation and maintenance of a gas detector or alarm in any potentially hazardous area.

(e) Fire- and gas-detection systems must be an approved type, and designed and installed in accordance with API RP 14C, API RP 14G, API RP 14F, API RP 14FZ, API RP 500, and API RP 505 (all incorporated by reference as specified in § 250.198).

§ 250.863 Electrical equipment.

You must design, install, and maintain electrical equipment and systems in accordance with the requirements in § 250.114.

§ 250.864 Erosion.

You must have a program of erosion control in effect for wells or fields that have a history of sand production. The erosion-control program may include sand probes, X-ray, ultrasonic, or other satisfactory monitoring methods. You must maintain records by lease that indicate the wells that have erosion-control programs in effect. You must also maintain the results of the programs for at least 2 years and make them available to BSEE upon request.

§ 250.865 Surface pumps.

(a) You must equip pump installations with the protective equipment required in API RP 14C, Appendix A—A.7, Pumps section A7 (incorporated by reference as specified in § 250.198).

(b) You must use pressure recording devices to establish the new operating pressure ranges for pump discharge sensors at any time when the normalized system pressure changes by 50 psig or 5 percent, whichever is higher. You must only maintain the most recent pressure recording information that you used to determine operating pressure ranges at your field office nearest the OCS facility or at another location conveniently available to the District Manager. The PSH sensor(s) must be set no higher than 15 percent or 5 psi, whichever is greater, above the highest operating pressure of the discharge line. But in all cases, you must set the PSH sensor sufficiently below the maximum allowable working pressure of the discharge piping. In addition, you must set the PSH sensor(s) at least (5 percent or 5 psi, whichever is greater) below the set pressure of the PSV to assure that the pressure source is shut-in before the PSV activates. You must set the PSL sensor(s) no lower than 15 percent or 5 psi, whichever is greater, below the lowest operating pressure of the discharge line in which it is installed.

(c) The PSL does not need to be placed into service until such time as the pump discharge pressure has risen above the PSL sensing point, as long as this time does not exceed 45 seconds.

(d) You may exclude the PSH and PSL sensors on small, low-volume pumps such as chemical injection-type pumps. This is acceptable if such a pump is used as a sump pump or transfer pump, has a discharge rating of less than ½ gallon per minute (gpm), discharges into piping that is 1 inch or less in diameter, and terminates in piping that is 2 inches or larger in diameter.

(e) You must install a TSE in the immediate vicinity of all pumps in hydrocarbon service or those powered by platform fuel gas.

(f) The pump maximum discharge pressure must be determined using the maximum possible suction pressure and the maximum power output of the driver.

§ 250.866 Personnel safety equipment.

You must maintain all personnel safety equipment located on a facility, whether required or not, in good working condition.

§ 250.867 Temporary quarters and temporary equipment.

(a) The District Manager must approve all temporary quarters to be installed on OCS facilities. You must equip temporary quarters with all safety devices required by API RP 14C, Appendix C (incorporated by reference as specified in § 250.198).

(b) The District Manager may require you to install a temporary firewater system in temporary quarters.

(c) Temporary equipment used for well testing and/or well clean-up needs to be approved by the District Manager.

§ 250.868 Non-metallic piping.

You may use non-metallic piping, such as that made from polyvinyl chloride, chlorinated polyvinyl chloride, and reinforced fiberglass only in atmospheric, primarily non-hydrocarbon service such as:

(a) Piping in galleys and living quarters;

(b) Open atmospheric drain systems;

(c) Overboard water piping for atmospheric produced water systems; and

(d) Firewater system piping.

§ 250.869 General platform operations.

(a) Surface or subsurface safety devices must not be bypassed or blocked out of service unless they are temporarily out of service for startup, maintenance, or testing. You may take only the minimum number of safety devices out of service. Personnel must monitor the bypassed or blocked-out functions until the safety devices are placed back in service. Any surface or subsurface safety device which is temporarily out of service must be flagged. A designated visual indicator must be used to identify the bypassed safety device. You must follow the monitoring procedures as follows:

(1) If you are using a non-computer-based system, meaning your safety system operates primarily with pneumatic supply or non-programmable electrical systems, you must monitor non-computer-based system bypassed safety devices by positioning monitoring personnel at either the control panel for the bypassed safety device, or at the bypassed safety device, or at the component that the bypassed safety device would be monitoring when in service. You must also ensure that monitoring personnel are able to view all relevant essential operating conditions until all bypassed safety devices are placed back in service and are able to initiate shut-in action in the event of an abnormal condition.

(2) If you are using a computer-based technology system, meaning a computer-controlled electronic safety system such as supervisory control and data acquisition and remote terminal units, you must monitor computer-based technology system bypassed safety devices by maintaining instantaneous communications at all times among remote monitoring personnel and the personnel performing maintenance, testing, or startup. Until all bypassed safety devices are placed back in service, you must also position monitoring personnel at a designated control station that is capable of the following:

(i) Displaying all relevant essential operating conditions that affect the bypassed safety device, well, pipeline, and process component. If electronic display of all relevant essential conditions is not possible, you must have field personnel monitoring the level gauges (Site glass) and pressure gauges in order to know the current operating conditions. You must be in communication with all field personnel monitoring the gauges;

(ii) Controlling the production process equipment and the entire safety system;

(iii) Displaying a visual indicator when safety devices are placed in the bypassed mode; and

(iv) Upon command, overriding the bypassed safety device and initiating shut-in action in the event of an abnormal condition.

(3) You must not bypass for startup any element of the emergency support system or other support system required by API RP 14C, Appendix C, (incorporated by reference as specified in § 250.198) without first receiving BSEE approval to depart from this operating procedure in accordance with 250.142. These systems include, but are not limited to:

(i) The ESD system to provide a method to manually initiate platform shutdown by personnel observing abnormal conditions or undesirable events. You do not have to receive approval from the District Manager for manual reset and/or initial charging of the system;

(ii) The fire loop system to sense the heat of a fire and initiate platform shutdown, and other fire detection devices (flame, thermal, and smoke) that are used to enhance fire detection capability. You do not have to receive approval from the District Manager for manual reset and/or initial charging of the system;

(iii) The combustible gas detection system to sense the presence of hydrocarbons and initiate alarms and platform shutdown before gas concentrations reach the lower explosive limit;

(iv) The adequate ventilation system;

(v) The containment system to collect escaped liquid hydrocarbons and initiate platform shutdown;

(vi) Subsurface safety valves, including those that are self-actuated (subsurface-controlled SSSV) or those that are activated by an ESD system and/or a fire loop (surface-controlled SSSV). You do not have to receive approval from the District Manager for routine operations in accordance with 250.817;

(vii) The pneumatic supply system; and

(viii) The system for discharging gas to the atmosphere.

(4) In instances where components of the ESD, as listed above in paragraph (3), are bypassed for maintenance, precautions must be taken to provide the equivalent level of protection that existed prior to the bypass.

(b) When wells are disconnected from producing facilities and blind flanged, or equipped with a tubing plug, or the master valves have been locked closed, you are not required to comply with the provisions of API RP 14C (incorporated by reference as specified in § 250.198) or this regulation concerning the following:

(1) Automatic fail-close SSVs on wellhead assemblies, and

(2) The PSH and PSL sensors in flowlines from wells.

(c) When pressure or atmospheric vessels are isolated from production facilities (*e.g.,* inlet valve locked closed or inlet blind-flanged) and are to remain isolated for an extended period of time, safety device testing in accordance with API RP 14C (incorporated by reference as specified in § 250.198) or this subpart is not required, with the exception of the PSV, unless the vessel is open to the atmosphere.

(d) All open-ended lines connected to producing facilities and wells must be plugged or blind-flanged, except those lines designed to be open-ended such as flare or vent lines.

(e) All new production safety system installations, component process control devices, and component safety devices must not be installed utilizing the same sensing points.

§ 250.870 Time delays on pressure safety low (PSL) sensors.

(a) You must apply industry standard Class B, Class C, and Class B/C logic to all applicable PSL sensors installed on process equipment, as long as the time delay does not exceed 45 seconds. Use of a PSL sensor with a time delay greater than 45 seconds requires BSEE approval of a request under § 250.141. You must document on your field test records use of a PSL sensor with a time delay greater than 45 seconds. For purposes of this section, PSL sensors are categorized as follows:

(1) Class B safety devices have logic that allows for the PSL sensors to be bypassed for a fixed time period (typically less than 15 seconds, but not more than 45 seconds). Examples include sensors used in conjunction with the design of pump and compressor panels such as PSL sensors, lubricator no-flows, and high-water jacket temperature shutdowns.

(2) Class C safety devices have logic that allows for the PSL sensors to be bypassed until the component comes into full service (*i.e.,* the time at which the startup pressure equals or exceeds the set pressure of the PSL sensor, the system reaches a stabilized pressure, and the PSL sensor clears).

(3) Class B/C safety devices have logic that allows for the PSL sensors to incorporate a combination of Class B and Class C circuitry. These devices are used to ensure that the PSL sensors are not unnecessarily bypassed during startup and idle operations, *e.g.,* Class B/C bypass circuitry activates when a pump is shut down during normal operations. The PSL sensor remains bypassed until the pump's start circuitry is activated and either

(i) The Class B timer expires no later than 45 seconds from start activation or

(ii) The Class C bypass is initiated until the pump builds up pressure above the PSL sensor set point and the PSL sensor comes into full service.

(b) If you do not install time delay circuitry that bypasses activation of PSL sensor shutdown logic for a specified time period on process and product transport equipment during startup and idle operations, you must manually bypass (pin out or disengage) the PSL sensor, with a time delay not to exceed 45 seconds. Use of a manual bypass that involves a time delay greater than 45 seconds requires approval from the appropriate BSEE District Manager of a request made under § 250.141.

§ 250.871 Welding and burning practices and procedures.

All welding, burning, and hot-tapping activities must be conducted according to the specific requirements in § 250.113. The BSEE approval of variances from your approved welding and burning practices and procedures may be requested in accordance with 250.141 regarding use of alternative procedures or equipment.

§ 250.872 Atmospheric vessels.

(a) You must equip atmospheric vessels used to process and/or store liquid hydrocarbons or other Class I liquids as described in API RP 500 or 505 (both incorporated by reference as specified in § 250.198) with protective equipment identified in API RP 14C, section A.5 (incorporated by reference as specified in § 250.198).

(b) You must ensure that all atmospheric vessels are designed and maintained to ensure the proper working conditions for LSH sensors. The LSH sensor bridle must be designed to prevent different density fluids from impacting sensor functionality. For atmospheric vessels that have oil buckets, the LSH sensor must be installed to sense the level in the oil bucket.

(c) You must ensure that all flame arrestors are maintained to ensure proper design function (installation of a system to allow for ease of inspection should be considered).

§ 250.873 Subsea gas lift requirements.

If you choose to install a subsea gas lift system, you must design your system in accordance with the following or as approved in your DWOP. You must:

(a) Design the gas lift supply pipeline in accordance with the API RP 14C (incorporated by reference as specified in § 250.198) for the gas lift supply system located on the platform.

(b) Meet the appropriate requirements in the following table:

If your subsea gas lift system introduces the lift gas to the . . .	Then you must install a . . .				Additional requirements
	API Spec 6A and API Spec 6AV1 (both incorporated by reference as specified in § 250.198) gas-lift shutdown valve (GLSDV), and . . .	FSV on the gas-lift supply pipeline . . .	PSHL on the gas-lift supply . . .	API Spec 6A and API Spec 6AV1 manual isolation valve . . .	
(1) Subsea Pipelines, Pipeline Risers, or Manifolds via an External Gas Lift Pipeline.	meet all of the requirements for the BSDV described in 250.835 and 250.836 on the gas-lift supply pipeline.	upstream (in board) of the GLSDV.	pipeline upstream (in board) of the GLSDV.	downstream (out board) of the PSHL and above the waterline. This valve does not have to be actuated.	(i) Ensure that the MAOP of a subsea gas lift supply pipeline is equal to the MAOP of the production pipeline. an actuated fail-safe close gas-lift isolation valve (GLIV) located at the point of intersection between the gas lift supply pipeline and the production pipeline, pipeline riser, or manifold. (ii) Install an actuated fail-safe close gas-lift isolation valve (GLIV) located at the point of intersection between the gas lift supply pipeline and the production pipeline, pipeline riser, or manifold. Install the GLIV downstream of the underwater safety valve(s) (USV) and/or AIV(s).
(2) Subsea Well(s) through the Casing String via an External Gas Lift Pipeline.	Locate the GLSDV within 10 feet of the first of access to the gas-lift riser or topsides umbilical termination assembly (TUTA) (i.e., within 10 feet of the edge of the platform if the GLSDV is horizontal, or within 10 feet above the first accessible working deck, excluding the boat landing and above the splash zone, if the GLSDV is in the vertical run of a riser, or within 10 feet of the TUTA if using an umbilical).	on the platform upstream (in board) of the GLSDV.	pipeline on the platform downstream (out board) of the GLSDV.	downstream (out board) of the PSHL and above the waterline. This valve does not have to be actuated.	Install an actuated, fail-safe-closed GLIV on the gas lift supply pipeline near the wellhead to provide the dual function of containing annular pressure and shutting off the gas lift supply gas. If your subsea trees or tubing head is equipped with an annulus master valve (AMV) or an annulus wing valve (AWV), one of these may be designated as the GLIV. Consider installing the GLIV external to the subsea tree to facilitate repair and or replacement if necessary.

If your subsea gas lift system introduces the lift gas to the . . .	Then you must install a . . .				Additional requirements
	API Spec 6A and API Spec 6AV1 (both incorporated by reference as specified in § 250.198) gas-lift shutdown valve (GLSDV), and . . .	FSV on the gas-lift supply pipeline . . .	PSHL on the gas-lift supply . . .	API Spec 6A and API Spec 6AV1 manual isolation valve . . .	
(3) Pipeline Risers via a Gas-Lift Line Contained within the Pipeline Riser.	locate the GLSDV within 10 feet of the first of access to the gas-lift riser or TUTA (i.e., within 10 feet of the edge of the platform if the GLSDV is horizontal, or within 10 feet above the first accessible working deck, excluding the boat landing and above the splash zone, if the GLSDV is in the vertical run of a riser, or within 10 feet of the TUTA if using an umbilical).	upstream (in board) of the GLSDV.	flowline upstream (in board) of the FSV.	downstream (out board) of the GLSDV.	(i) Ensure that the gas-lift supply flowline from the gas-lift compressor to the GLSDV is pressure-rated for the MAOP of the pipeline riser. Ensure that any surface equipment associated with the gas-lift system is rated for the MAOP of the pipeline riser. (ii) Ensure that the gas-lift compressor discharge pressure never exceeds the MAOP of the pipeline riser. (iii) Suspend and seal the gas-lift flowline contained within the production riser in a flanged API Spec. 6A component such as an API Spec. 6A tubing head and tubing hanger or a component designed, constructed, tested, and installed to the requirements of API Spec. 6A. Ensure that all potential leak paths upstream or near the production riser BSDV on the platform provide the same level of safety and environmental protection as the production riser BSDV. In addition, ensure that this complete assembly is fire-rated for 30 minutes. Attach the GLSDV by flanged connection directly to the API Spec. 6A component used to suspend and seal the gas-lift line contained within the production riser. To facilitate the repair or replacement of the GLSDV or production riser BSDV, you may install a manual isolation valve between the GLSDV and the API Spec. 6A component used to suspend and seal the gas-lift line contained within the production riser, or outboard of the production riser BSDV and inboard of the API Spec. 6A component used to suspend and seal the gas-lift line contained within the production riser.

(c) Follow the valve closure times and hydraulic bleed requirements according to your approved DWOP for the following:

(1) Electro-hydraulic control system with gas lift,

(2) Electro-hydraulic control system with gas lift with loss of communications,

(3) Direct-hydraulic control system with gas lift.

(d) Follow the gas lift valve testing requirements according to the following table:

Type of gas lift system	Valve	Allowable leakage rate	Testing frequency
(i) Gas Lifting a subsea pipeline, pipeline riser, or manifold via an external gas lift pipeline.	GLSDV	Zero leakage	Monthly, not to exceed 6 weeks.
	GLIV	N/A	Function tested quarterly, not to exceed 120 days.
(ii) Gas Lifting a subsea well through the casing string via an external gas lift pipeline.	GLSDV	Zero leakage	Monthly, not to exceed 6 weeks.
	GLIV	400 cc per minute of liquid or 15 scf per minute of gas.	Function tested quarterly, not to exceed 120 days.
(iii) Gas lifting the pipeline riser via a gas lift line contained within the pipeline riser.	GLSDV	Zero leakage	Monthly, not to exceed 6 weeks.

§ 250.874 Subsea water injection systems.

If you choose to install a subsea water injection system, you must design your system in accordance with the following or as approved in your DWOP. You must:

(a) Adhere to the water injection requirements described in API RP 14C (incorporated by reference as specified in § 250.198) for the water injection equipment located on the platform. In accordance with § 250.830, either a surface-controlled SSSV or a water injection valve (WIV) that is selfactivated and not controlled by emergency shut-down (ESD) or sensor activation must be installed in a subsea water injection well.

(b) Equip a water injection pipeline with a surface FSV and water injection shutdown valve (WISDV) on the surface facility.

(c) Install a PSHL sensor upstream (in board) of the FSV and WISDV.

(d) All subsea tree(s), wellhead(s), connector(s), tree valves, and an surface-controlled SSSV or WIV associated with a water injection system must be rated for the maximum anticipated injection pressure.

(e) Consider the effects of hydrogen sulfide (H2S) when designing your water flood system.

(f) Follow the valve closure times and hydraulic bleed requirements according to your approved DWOP for the following:

(1) Electro-hydraulic control system with water injection,

(2) Electro-hydraulic control system with water injection with loss of communications,

(3) Direct-hydraulic control system with water injection.

(g) Follow the WIV testing requirements according to the following:

(1) WIV testing table,

Valve	Allowable leakage rate	Testing frequency
(i) WISDV	Zero leakage	Monthly, not to exceed 6 weeks.
(ii) Surface-controlled SSSV or WIV	400 cc per minute of liquid or 15 scf per minute of gas.	Semiannually, not to exceed 6 calendar months.

(2) Should a designated USV on a water injection well fail to test, notify the appropriate BSEE District Manager, and either designate another API Spec 6A and API Spec. 6AV1 (both incorporated by reference as specified in § 250.198) certified subsea valve as your USV, or modify the valve closure time of the surface-controlled SSSV or WIV to close within 20 minutes after sensor activation for a water injection line PSHL or platform ESD/TSE (host). If a USV on a water injection well fails and the surface-controlled SSSV or WIV cannot be tested because of low reservoir pressure, submit a request to the appropriate BSEE District Manager with an alternative plan that ensures subsea shutdown capabilities.

(3) Function test the WISDV quarterly if you are operating under a departure approval to not test the WISDV. You may request approval from the appropriate BSEE District Manager to forgo testing the WISDV until the shut-in tubing pressure of the water injection well is greater than the external hydrostatic pressure, provided that the USVs meet the allowable leakage rate listed in the valve closure testing table in § 250.880 (c)(4)(ii). Should the USVs fail to meet the allowable leakage rate, submit a request to the appropriate BSEE District Manager with an alternative plan that ensures subsea shutdown capabilities.

(f) If you experience a loss of communications during water injection operations, comply with the following:

(1) Notify the appropriate BSEE District Manager within 12 hours after loss of communication detection; and

(2) Obtain approval from the appropriate BSEE District Manager, to continue to inject with loss of communication. The District Manager may also order a shut-in. In that case, the BSEE District Manager may approve an alternate hydraulic bleed schedule to allow for an orderly shut-in.

§ 250.875 Subsea Pump Systems.

If you choose to install a subsea pump system, you must design your system in accordance with the following or as approved in your DWOP. You must:

(a) Install an isolation valve at the inlet of your subsea pump module.

(b) Install a PSHL sensor upstream of the BSDV, if the maximum possible discharge pressure of the subsea pump operating in a dead head condition (that is the maximum shut-in tubing pressure at the pump inlet and a closed BSDV) is less than the MAOP of the associated pipeline.

(c) Comply with the following, if the maximum possible discharge pressure of the subsea pump operating in a dead head situation could be greater than the MAOP of the pipeline:

(1) Install, at minimum, two independent functioning PSHL sensors upstream of the subsea pump and two independent functioning PSHL sensors downstream of the pump.

(i) Ensure PSHL sensors are operational when the subsea pump is in service; and

(ii) Ensure that PSHL activation will shut down the subsea pump, the subsea inlet isolation valve, and either the designated USV1, the USV2, or the alternate isolation valve.

(iii) If more than two PSHL sensors are installed upstream and downstream of the subsea pump for operational flexibility, then a 2 out of 3 voting logic may be implemented in which the subsea pump remains operational provided a minimum of two independent PSHL sensors are functional both upstream and downstream of the pump.

(2) Interlock the subsea pump motor with the BSDV to ensure that the pump cannot start or operate when the BSDV is closed, incorporate the following permissive signals into the control system for your subsea pump, and ensure that the subsea pump is not able to be started or re-started unless:

(i) The BSDV is open;

(ii) All automated valves downstream of the subsea pump are open;

(iii) The upstream subsea pump isolation valve is open; and

(iv) All alarms associated with the subsea pump operation (pump temperature high, pump vibration high, pump suction pressure high, pump discharge pressure high, pump suction flow low) are cleared or continuously monitored (personnel should observe visual indicators displayed at a designated control station and have the capability to initiate shut-in action in the event of an abnormal condition).

(3) Monitor the separator for seawater.

(4) Ensure that the subsea pump systems are controlled by an electro-hydraulic control system.

(d) Follow the valve closure times and hydraulic bleed requirements according to your approved DWOP for the following:

(1) Electro-hydraulic control system with a subsea pump,

(2) A loss of communications with the subsea wells and not the subsea pump control system without a ESD or sensor activation,

(3) A loss of communications with the subsea pump control system, but not the subsea wells,

(4) A loss of communications with the subsea wells and the subsea pump control system.

(e) Follow the subsea pump testing requirements by:

(1) Performing a complete subsea pump function test, including full shutdown after any intervention, or changes to the software and equipment affecting the subsea pump; and

(2) Testing the subsea pump shutdown including PSHL sensors both

upstream and downstream of the pump each quarter, but in no case more than 120 days between tests. This testing may be performed concurrently with the ESD function test.

§ 250.876 Fired and Exhaust Heated Components.

Every 5 years you must have a qualified third party remove, inspect, repair, or replace tube-type heaters that are equipped with either automatically controlled natural or forced draft burners installed in either atmospheric or pressure vessels that heat hydrocarbons and/or glycol. If removal and inspection indicates tube-type heater deficiencies, you must complete and document repairs or replacements. You must document the inspection results, retain such documentation for at least 5 years, and make them available to BSEE upon request.

§§ 250.877 through 250.879 [Reserved]

Safety Device Testing

§ 250.880 Production safety system testing.

(a) Notification. You must:

(1) Notify District Manager at least 72 hours before commencing production, so that BSEE may witness a preproduction test and conduct a preproduction inspection of the integrated safety system.

(2) Notify the District Manager upon commencement of production so that BSEE may conduct a complete inspection.

(3) Notify the District Manager and receive BSEE approval before you perform any subsea intervention that modifies the existing subsea infrastructure in a way that may affect the casing monitoring capabilities and testing frequencies contained in the table set forth in paragraph (c)(4).

(b) Testing methodologies. You must:

(1) Test safety valves and other equipment at the intervals specified in the tables set forth in paragraph (c) or more frequently if operating conditions warrant; and

(2) Perform testing and inspection in accordance with API RP 14C, Appendix D (incorporated by reference as specified in § 250.198), and the additional requirements found in the tables of this section or as approved in the DWOP for your subsea system.

(c) Testing frequencies and allowable parameters.

(1) The following testing requirements apply to subsurface safety devices on dry tree wells:

Item name	Testing frequency, allowable leakage rates, and other requirements
(i) Surface-controlled SSSVs (including devices installed in shut-in and injection wells).	Not to exceed 6 months. Also test in place when first installed or reinstalled. If the device does not operate properly, or if a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 cubic feet per minute is observed, the device must be removed, repaired, and reinstalled or replaced. Testing must be according to API RP 14B (ISO 10417:2004) (incorporated by reference as specified in § 250.198) to ensure proper operation.
(ii) Subsurface-controlled SSSVs	Not to exceed 6 months for valves not installed in a landing nipple and 12 months for valves installed in a landing nipple. The valve must be removed, inspected, and repaired or adjusted, as necessary, and reinstalled or replaced.
(iii) Tubing plug	Not to exceed 6 months. Test by opening the well to possible flow. If a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 cubic feet per minute is observed, the plug must be removed, repaired, and reinstalled, or replaced. An additional tubing plug may be installed in lieu of removal.
(iv) Injection valves	Not to exceed 6 months. Test by opening the well to possible flow. If a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 cubic feet per minute is observed, the valve must be removed, repaired and reinstalled, or replaced.

(2) The following testing requirements apply to surface valves:

Item name	Testing frequency and requirements
(i) PSVs	Once each 12 months, not to exceed 13 months between tests. Valve must either be bench-tested or equipped to permit testing with an external pressure source. Weighted disc vent valves used as PSVs on atmospheric tanks may be disassembled and inspected in lieu of function testing.
(ii) Automatic inlet SDVs that are actuated by a sensor on a vessel or compressor.	Once each calendar month, not to exceed 6 weeks between tests.
(iii) SDVs in liquid discharge lines and actuated by vessel low-level sensors.	Once each calendar month, not to exceed 6 weeks between tests.
(iv) SSVs	Once each calendar month, not to exceed 6 weeks between tests. Valves must be tested for both operation and leakage. You must test according to API RP 14H (incorporated by reference as specified in § 250.198). If an SSV does not operate properly or if any fluid flow is observed during the leakage test, the valve must be immediately repaired or replaced.
(v) FSVs	Once each calendar month, not to exceed 6 weeks between tests. All FSVs must be tested, including those installed on a host facility in lieu of being installed at a satellite well. You must test FSVs for leakage in accordance with the test procedure specified in API RP 14C, appendix D, section D4, table D2 subsection D (incorporated by reference as specified in § 250.198). If leakage measured exceeds a liquid flow of 400 cubic centimeters per minute or a gas flow of 15 cubic feet per minute, the FSV must be repaired or replaced.

(3) The following testing requirements apply to surface safety systems and devices:

Item name	Testing frequency and requirements
(i) Pumps for firewater systems	Must be inspected and operated according to API RP 14G, Section 7.2 (incorporated by reference as specified in § 250.198).
(ii) Fire- (flame, heat, or smoke) detection systems.	Must be tested for operation and recalibrated every 3 months provided that testing can be performed in a non-destructive manner. Open flame or devices operating at temperatures that could ignite a methane-air mixture must not be used. All combustible gas-detection systems must be calibrated every 3 months.
(iii) ESD systems	(A) Pneumatic based ESD systems must be tested for operation at least once each calendar month, not to exceed 6 weeks between tests. You must conduct the test by alternating ESD stations monthly to close at least one wellhead SSV and verify a surface-controlled SSSV closure for that well as indicated by control circuitry actuation. (B) Electronic based ESD systems must be tested for operation at least once every three calendar months, not to exceed 120 days between tests. The test must be conducted by alternating ESD stations to close at least one wellhead SSV and verify a surface-controlled SSSV closure for that well as indicated by control circuitry actuation. (C) Electronic/pneumatic based ESD systems must be tested for operation at least once every three calendar months, not to exceed 120 days between tests. The test must be conducted by alternating ESD stations to close at least one wellhead SSV and verify a surface-controlled SSSV closure for that well as indicated by control circuitry actuation.
(iv) TSH devices	Must be tested for operation at least once every 12 months, excluding those addressed in paragraph (b)(3)(v) of this section and those that would be destroyed by testing. Those that could be destroyed by testing must be visually inspected and the circuit tested for operations at least once every 12 months.
(v) TSH shutdown controls installed on compressor installations that can be nondestructively tested.	Must be tested every 6 months and repaired or replaced as necessary.
(vi) Burner safety low	Must be tested at least once every 12 months.
(vii) Flow safety low devices	Must be tested at least once every 12 months.
(viii) Flame, spark, and detonation arrestors	Must be visually inspected at least once every 12 months.
(ix) Electronic pressure transmitters and level sensors: PSH and PSL; LSH and LSL.	Must be tested at least once every 3 months, but no more than 120 days elapse between tests.
(x) Pneumatic/electronic switch PSH and PSL; pneumatic/electronic switch/electric analog with mechanical linkage LSH and LSL controls.	Must be tested at least once each calendar month, but with no more than 6 weeks elapsed time between tests.

(4) The following testing requirements apply to subsurface safety devices and associated systems on subsea tree wells:

Item name	Testing frequency, allowable leakage rates, and other requirements
(i) Surface-controlled SSSVs (including devices installed in shut-in and injection wells).	Tested semiannually, not to exceed 6 months. If the device does not operate properly, or if a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 cubic feet per minute is observed, the device must be removed, repaired, and reinstalled or replaced. Testing must be according to API RP 14B (ISO 10417:2004) (incorporated by reference as specified in § 250.198) to ensure proper operation, or as approved in your DWOP.
(ii) USVs	Tested quarterly, not to exceed 120 days. If the device does not function properly, or if a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 cubic feet per minute is observed, the valve must be removed, repaired and reinstalled, or replaced.
(iii) BSDVs	Tested monthly, not to exceed 6 weeks. Valves must be tested for both operation and leakage. You must test according to API RP 14H for SSVs (incorporated by reference as specified in § 250.198). If a BSDV does not operate properly or if any fluid flow is observed during the leakage test, the valve must be immediately repaired or replaced.
(iv) Electronic ESD logic	Tested monthly, not to exceed 6 weeks.
(v) Electronic ESD function	Tested quarterly, not to exceed 120 days. Shut-in at least one well during the ESD function test. If multiple wells are tied back to the same platform, a different well should be shut-in with each quarterly test.

(5) The following testing and other requirements apply to subsea wells shut-in and disconnected from monitoring capability for periods greater than 6 months:

(i) Each well must be left with three pressure barriers: A closed and tested surface-controlled SSSV, a closed and tested USV, and one additional closed and tested tree valve.

(ii) Acceptance criteria for the tested pressure barriers prior to the rig leaving the well are as follows:

(A) The surface-controlled SSSV must be tested for leakage in accordance with § 250.828(c).

(B) The USV and other pressure barrier must be tested to confirm zero leakage.

(iii) A sealing pressure cap must be installed on the flowline connection hub until installation of and connection to the flowline. A pressure cap must be designed to accommodate monitoring for pressure between the production wing valve and cap. A diagnostics capability must be integrated into the design such that a remotely operated vehicle can bleed pressure off and monitor for buildup, confirming barrier integrity.

(iv) Pressure monitoring at the sealing pressure cap on the flowline connection hub must be performed in each well at intervals not to exceed 12 months from the time of initial testing (prior to demobilizing rig from field).

(v) A drilling vessel capable of intervention into the disconnected well must be in the field or readily accessible for use until the wells are brought on line.

(vi) The shut-in period for each disconnected well must not exceed 24 months, unless authorized by BSEE.

§§ 250.881–250.889 [Reserved]

Records and Training

§ 250.890 Records.

(a) You must maintain records that show the present status and history of each safety device. Your records must include dates and details of installation, removal, inspection, testing, repairing, adjustments, and reinstallation.

(b) You must maintain these records for at least 2 years. You must maintain the records at your field office nearest the OCS facility and a secure onshore location. These records must be available for review by a representative of BSEE.

(c) You must submit to the appropriate District Manager a contact list for all OCS operated platforms at least annually or when contact information is revised. The contact list must include:

(1) Designated operator name;

(2) Designated person in charge (PIC);

(3) Facility phone number(s), if applicable;

(4) Facility fax number, if applicable;

(5) Facility radio frequency, if applicable;

(6) Facility helideck rating and size, if applicable; and

(7) Facility records location if not contained on the facility.

§ 250.891 Safety device training.

You must ensure that personnel installing, repairing, testing, maintaining, and operating surface and subsurface safety devices and personnel operating production platforms, including but not limited to separation, dehydration, compression, sweetening, and metering operations, are trained in accordance with the procedures in subpart S of this part.

§§ 250.892–250.899 [Reserved]

[FR Doc. 2013–19861 Filed 8–21–13; 8:45 am]

BILLING CODE 4310–VH–P