Displaying title 30, up to date as of 11/08/2021. Title 30 was last amended 11/01/2021.

ENHANCED CONTENT - TABLE OF CONTENTS

Title 30

Subpart H - Oil and Gas Production Safety Systems

Source: 81 FR 60918, Sept. 7, 2016, unless otherwise noted.

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. Before you commence production on a new production facility:

(1) BSEE must approve your production safety system application, as required in § 250.842.

(2) You must request a preproduction inspection by notifying the District Manager at least 72 hours before you plan to commence initial production, as required under § 250.880(a)(1).

(b) For all new production systems on fixed leg platforms, you must comply with API RP 14J (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); and spars), you must:

(1) Comply with API RP 14J;

(2) Meet the production riser standards of API RP 2RD (incorporated by reference as specified in § 250.198), provided that you may not install single bore production risers from floating production facilities;

(3) Design all stationkeeping (*i.e.,* anchoring and mooring) systems for floating production facilities to meet the standards of API RP 2SK and API RP 2SM (both incorporated by reference as specified in § 250.198); and

(4) Design stationkeeping (*i.e.,* anchoring and mooring) systems for floating facilities to meet the structural requirements of §§ 250.900 through 250.921.

(d) If there are any conflicts between the documents incorporated by reference and the requirements of this subpart, you must follow the requirements of this subpart.

(e) You may use alternate procedures or equipment during operations after receiving approval from the District Manager. You must present your proposed alternate procedures or equipment as required by § 250.141.

(f) You may apply for a departure from the operating requirements of this subpart as provided by § 250.142. Your written request must include a justification showing why the departure is necessary and appropriate.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49256, Sept. 28, 2018]

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

(a) ***SPPE equipment.*** 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. 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 shutdown valves (BSDV) and their actuators. For subsea wells, the BSDV is the surface equivalent of an SSV on a surface well;

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

(4) Subsurface safety valves (SSSV) and associated safety valve locks and landing nipples; and

(5) Gas lift shutdown valves (GLSDV) and their actuators associated with subsea systems.

(b) ***Certification of SPPE.*** SPPE that is manufactured and marked pursuant to ANSI/API Spec. Q1 (incorporated by reference as specified in § 250.198), is considered as certified SPPE under this part. All other SPPE is considered as not certified, unless approved in accordance with paragraph (c) of this section.

(c) ***Accepting SPPE manufactured under other quality assurance programs.*** BSEE may exercise its discretion to accept SPPE manufactured under a quality assurance program other than ANSI/API Spec. Q1, provided that the alternative quality assurance program is verified as equivalent to API Spec. Q1 by an appropriately qualified entity and that the operator submits a request to BSEE containing relevant information about the alternative program and receives BSEE approval. In addition, an operator may request that BSEE accept SPPE that is marked with a third-party certification mark other than the API monogram. All requests under this paragraph should be submitted to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; VAE-ORP; 45600 Woodland Road, Sterling, VA 20166.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49256, Sept. 28, 2018]

§ 250.802 Requirements for SPPE.

(a) All SSVs, BSDVs, USVs, and GLSDVs and their actuators must meet all of the specifications contained in ANSI/API Spec. 6A and API Spec. 6AV1 (both incorporated by reference in § 250.198).

(b) All SSSVs and their actuators must meet all of the specifications and recommended practices of ANSI/API Spec. 14A and ANSI/API RP 14B, including all annexes (both incorporated by reference as specified in § 250.198). Subsurface-controlled SSSVs are not allowed on subsea wells.

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

(1) You must ensure that each device is designed to function in the conditions to which it may be exposed; including temperature, pressure, flow rates, and environmental conditions.

(i) The device design must be tested by an independent test agency according to the test requirements in the appropriate standard for that device (API Spec. 6AV1 or ANSI/API Spec. 14A), as identified in paragraphs (a) and (b) of this section.

(ii) You must maintain a description of the process you used to ensure the device is designed to function as required in paragraphs (a) and (c)(1) of this section and provide that description to BSEE upon request.

(iii) If you remove any SPPE from service and install the device at a different location, you must have a qualified third party review and certify that each device will function as designed under the conditions to which it may be exposed.

(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 and use SPPE according to the following table.

If . . .	Then . . .
(1) You need to install any SPPE	You must install SPPE that conforms to § 250.801.
(2) A non-certified SPPE is already in service	It may remain in service.
(3) A non-certified SPPE requires offsite repair, re-manufacturing, or any hot work such as welding	You must replace it with SPPE that conforms to § 250.801.

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

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49256, Sept. 28, 2018]

§ 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 ANSI/API Spec. 6A for SSVs, BSDVs, GLSDVs and USVs. You must follow the failure reporting requirements contained in section 7.10 of ANSI/API Spec. 14A and Annex F of ANSI/API RP 14B for SSSVs (all incorporated by reference in § 250.198). Within 30 days after the discovery and identification of the failure, you must provide a written notice of equipment failure to the manufacturer of such equipment and to BSEE through the Chief, Office of Offshore Regulatory Programs, unless BSEE has designated a third party as provided in paragraph (d) of this section. A failure is any condition that prevents the equipment from meeting the functional specification or purpose.

(b) You must ensure that an investigation and a failure analysis are performed within 120 days of the failure to determine the cause of the failure. If the investigation and analyses are performed by an entity other than the manufacturer, you must ensure that the analysis report is submitted to the manufacturer and to BSEE through the Chief, Office of Offshore Regulatory Programs, unless BSEE has designated a third party as provided in paragraph (d) of this section. You must also ensure that the results of the investigation and any corrective action are documented in 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 BSEE through the Chief, Office of Offshore Regulatory Programs, unless BSEE has designated a third party as provided in paragraph (d) of this section.

(d) BSEE may designate a third party to receive the data required by paragraphs (a) through (c) of this section on behalf of BSEE. If BSEE designates a third party, you must submit the information required in this section to the designated third party, as directed by BSEE.

[83 FR 49256, Sept. 28, 2018]

§ 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) or Application for Permit to Modify (APM), and 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 analyses;

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

(3) An explanation of why the analyses, processes, 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 psia 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 psia 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) 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, you must conduct production operations in accordance with that section and other relevant requirements of this subpart.

(b) You must receive approval through the DWOP process (§§ 250.286 through 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] 2

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. You must install flow couplings above and below the subsurface safety devices. These subsurface safety devices include the following devices and any associated safety valve lock 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 SSSVs - dry trees.

All surface-controlled and subsurface-controlled SSSVs, safety valve locks, and landing nipples installed in the OCS must conform to the requirements specified in §§ 250.801 through 250.803.

§ 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 District Manager approval to situate the surface controls at a remote location.

(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 submit an APM or a request to the District Manager for approval to equip a dry tree well with a subsurface-controlled SSSV in lieu of a surface-controlled SSSV, if the subsurface-controlled SSSV is installed in a well equipped with a surface-controlled SSSV that 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, and operate (including repair, maintain, and test) 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 on a case-by-case basis.

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

(c) 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.

(d) You must design, install, maintain, inspect, repair, and test all SSSVs in accordance with ANSI/API RP 14B (incorporated by reference in § 250.198). For additional SSSV testing requirements, refer to § 250.880.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49257, Sept. 28, 2018]

§ 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 that are 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 must 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) Prior to removal, 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 by a support vessel, or a pump-through plug must be 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 STD 6AV2 (incorporated by reference in § 250.198). If any SSV does not operate properly, or if any gas and/or liquid fluid flow is observed during the leakage test as described in § 250.880, then you must shut-in all sources to the SSV and repair or replace the valve before resuming production.

[83 FR 49257, Sept. 28, 2018]

§ 250.821 Emergency action and safety system shutdown - dry trees.

(a) If your facility is impacted or will potentially be impacted by an emergency situation (*e.g.,* an impending National Weather Service-named tropical storm or hurricane, ice events, or post-earthquake), you must:

(1) Properly install a subsurface safety device on any well that is not yet equipped with a subsurface safety device and that is capable of natural flow, as soon as possible, with due consideration being given to personnel safety.

(2) You must shut-in (by closing the SSV and the surface-controlled SSSV) the following types of wells:

(i) All oil wells, and

(ii) All gas wells requiring compression.

(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 alternative design-delayed closure time of greater than 2 minutes based on the mechanical/production characteristics of the individual well.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49257, Sept. 28, 2018]

§§ 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. You must also install flow couplings above and below the subsurface safety devices. For instances where the well at issue is incapable of natural flow, you may seek District Manager approval for using alternative procedures or equipment, 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. Subsurface safety devices include the following and any associated safety valve lock 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.

§ 250.826 Specifications for SSSVs - subsea trees.

All SSSVs, safety valve locks, and landing nipples installed on the OCS 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.

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 §§ 250.829 and 250.830. The surface controls must be located on the host facility.

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

You must design, install, and operate (including repair, maintain, and test) 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, permafrost, hydrate formation, or paraffin problems, the District Manager may approve an alternate setting depth on a case-by-case basis.

(b) The well must not be open to flow while an SSSV is inoperable, unless specifically approved by the District Manager in an APM.

(c) You must design, install, maintain, inspect, repair, and test all SSSVs in accordance with your Deepwater Operations Plan (DWOP) and ANSI/API RP 14B (incorporated by reference in § 250.198). For additional SSSV testing requirements, refer to § 250.880.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49257, Sept. 28, 2018]

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

(a) You must equip all new subsea 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) 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. If your controls employ an electro-hydraulic control umbilical and the hydraulic control pressure to the individual well cannot be isolated, a surface-controlled SSSV is considered inoperative if 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) When warranted by conditions, such as unstable bottom conditions, permafrost, hydrate formation, and paraffin problems, the District Manager must approve the setting depth of the subsurface safety device for a shut-in well on a case-by-case basis.

§ 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 would affect your ability to monitor casing pressure or to test any subsea valves or equipment, you must contact the appropriate 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 pump down-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 device.

(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 ANSI/API Spec. 6A and API Spec. 6AV1 (both incorporated by reference 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. As provided in paragraph (b) of this section, you must inform BSEE if the primary USV designation changes.

(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 the USV2. If the USV1 fails to operate properly or exhibits a leakage rate greater than allowed in § 250.880, you must notify the appropriate 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. The USV2 must be located upstream of the choke.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49257, Sept. 28, 2018]

§ 250.834 Use of USVs.

You must install, maintain, inspect, repair, and test any valve designated as the primary USV in accordance with this subpart, your DWOP (as specified in §§ 250.286 through 250.295), and API STD 6AV2 (incorporated by reference in § 250.198). For additional USV testing requirements, refer to § 250.880.

[83 FR 49257, Sept. 28, 2018]

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

You must install a BSDV on the pipeline boarding riser. All new BSDVs and any BSDVs removed from service for remanufacturing or repair and their actuators installed on the OCS must meet the requirements specified in §§ 250.801 through 250.803. In addition, you must:

(a) Ensure that the internal design pressure(s) of the pipeline(s), riser(s), and BSDV(s) is fully rated for the maximum pressure of any input source and complies 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.

You must install, inspect, maintain, repair, and test all new BSDVs, as well as all BSDVs that you remove from service for remanufacturing or repair, in accordance with API STD 6AV2 (incorporated by reference in § 250.198) for SSVs. If any BSDV does not operate properly or if any gas fluid and/or liquid fluid flow is observed during the leakage test, as described in § 250.880, you must shut-in all sources to the BSDV and immediately repair or replace the valve.

[83 FR 49257, Sept. 28, 2018]

§ 250.837 Emergency action and safety system shutdown - subsea trees.

(a) If your facility is impacted or will potentially be impacted by an emergency situation (*e.g.,* an impending National Weather Service-named tropical storm or hurricane, ice events, or post-earthquake), you must shut-in all subsea wells unless otherwise approved by the District Manager. A shut-in is defined as a closed BSDV, USV, GLSDV, and surface-controlled SSSV.

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

(1) Suspend production from all 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 or other type of workover or intervention vessel and the production facility control room and develop a dropped objects plan, as required in § 250.714. If an object is dropped, you must immediately secure the well directly under the MODU or other type of workover or intervention vessel while simultaneously communicating with the platform to shut-in all affected wells. You must also maintain without disruption, and continuously verify, communication between the production facility and the MODU or other type of workover or intervention vessel. If communication is lost between the MODU or other type of workover or intervention vessel and the platform for 20 or more minutes, 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 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 District Manager.

(3) ***ESD/TSE (platform).*** In the event of an ESD activation that is initiated because of a platform ESD or platform TSE 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 dropped object from a MODU or other type of workover or intervention vessel, you must secure all wells in the proximity of the MODU or other type of workover or intervention vessel 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 District Manager before resuming production.

(d) Following an ESD or fire, 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 and cannot be reopened inadvertently.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49257, Sept. 28, 2018]

§ 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 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 as long as communication is maintained with the platform or with the MODU or other type of workover vessel:

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. . .	Y h sys
(1) Process upset	Close within 45 seconds after sensor activation	[no requirements]			[no requirements]	[no requirements]	[no req
(2) Pipeline 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 60 minutes after sensor activation. If you use a 60-minute manual resettable timer, you may continue to reset the time for closure up to a maximum of 24 hours total	[no requirements]	Initi unr blee 24 h sen acti

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. . .	Y h sys
(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 manual 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 manual resettable timer you must initiate unrestricted bleed within 24 hours	Initi unr blee 60 afte sen acti you min mar rese tim mus unr blee 24
(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	Initi unr blee 60 afte sen acti
(5) Subsea ESD (MODU or other type of workover vessel, Dropped object)	[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	Initi unr blee 10 afte acti

(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 paragraph (d) of this section, you must notify the appropriate 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 paragraph (d) of this section, you must notify the appropriate 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. You must bleed the other hydraulic system within 180 minutes after loss of communication.

(3) You must obtain approval from the appropriate District Manager before continuing 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 timing table that your system is able to achieve. The appropriate 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].
(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.

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. . .
(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.
(5) Subsea ESD (MODU or other type of workover vessel), Dropped object	[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 a direct-hydraulic control system?

(a) If you have a 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 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]

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) 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) Subsea ESD (MODU or other type of workover vessel), Dropped object	[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 (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 § 250.1004.

(b) You must design, install, inspect, repair, test, and maintain in operating condition all platform production process piping in accordance with API RP 14E and API 570 (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.

(c) If you plan to make a modification to any production safety system that also involves a major modification to the platform structure, you must follow the requirements in § 250.900(b)(2). A major modification to a platform structure is defined in § 250.900(b)(2).

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49257, Sept. 28, 2018]

§ 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. The District Manager must approve your production safety system application before you commence production through or otherwise use the new or modified system. The application must include the design documentation prescribed as follows:

You must submit:	Details and/or additional requirements:
(1) Safety analysis flow diagram (API RP 14C, Annex B) and Safety Analysis Function Evaluation (SAFE) chart (API RP 14C, section 6.3.3) (incorporated by reference in § 250.198)	Your safety analysis flow diagram must show the following: (i) Well shut-in tubing pressure; (ii) Pressure relieving device set points; (iii) Size, capacity, and design working pressures of separators, flare scrubbers, heat exchangers, treaters, storage tanks, compressors, and metering devices;
	(iv) Size, capacity, design working pressures, and maximum discharge pressure of hydrocarbon-handling pumps;
	(v) 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 API RP 505 (both incorporated by reference in § 250.198); and
	(vi) Piping sizes and maximum allowable working pressures as determined in accordance with API RP 14E (incorporated by reference in § 250.198), including the locations of piping specification breaks.
(2) Electrical one-line diagram;	Showing elements including generators, circuit breakers, transformers, bus bars, conductors, automatic transfer switches, uninterruptable power supply (UPS) and associated battery banks, dynamic (motor) loads, and static loads (*e.g.,* electrostatic treater grid, lighting panels). You must also include a functional legend.

You must submit:	Details and/or additional requirements:
(3) Area classification diagram;	A plan for each platform deck and outlining all classified areas. You must classify areas according to API RP 500 or API RP 505 (both incorporated by reference in § 250.198). The plan must contain: (i) All major production equipment, wells, and other significant hydrocarbon and class 1 flammable sources, and a description of the type of decking, ceiling, walls (e.g., grating or solid), and firewalls; and (ii) The location of generators and any buildings (e.g., control rooms and motor control center (MCC) buildings) or major structures on the platform.
(4) A piping and instrumentation diagram, for new facilities;	A detailed flow diagram which shows the piping and vessels in the process flow, together with the instrumentation and control devices.
(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) You must develop and maintain the following design documents and make them available to BSEE upon request:

Diagram:	Details and/or additional requirements:
(1) Additional electrical system information;	(i) Cable tray/conduit routing plan that identifies the primary wiring method (e.g., type cable, cable schedule, conduit, wire); and
	(ii) Panel board/junction box location plan, if this information is not shown on the area classification diagram required in paragraph (a)(3) of this section.
(2) 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; and the method used for detection.
(3) Revised piping and instrumentation diagram for existing facilities;	A detailed flow diagram which shows the piping and vessels in the process flow, together with the instrumentation and control devices.

(c) In the production safety system application, you must also certify the following:

(1) That all electrical systems were designed according to API RP 14F or API RP 14FZ, as applicable (incorporated by reference in § 250.198);

(2) That the design documents for the mechanical and electrical systems that you are required to submit under paragraph (a) of this section are sealed by a licensed professional engineer. For modified systems, only the modifications are required to be sealed by a licensed professional engineer(s). The professional engineer must be licensed in a State or Territory of the United States and have sufficient expertise and experience to perform the duties; and

(3) That a hazards analysis was performed in accordance with § 250.1911 and API RP 14J (incorporated by reference in § 250.198), and that you have a hazards analysis program in place to assess potential hazards during the operation of the facility.

(d) Within 90 days after placing new or modified production safety systems in service, you must submit to the District Manager the as-built diagrams for the new or modified production safety systems outlined in paragraphs (a)(1), (2), and (3) of this section. You must certify in an accompanying letter that the as-built design documents have been reviewed for compliance with applicable regulations and accurately represent the new or modified system as installed. The drawings must be clearly marked "as-built."

(e) You must maintain approved and supporting design documents required under paragraphs (a) and (b) of this section at your offshore field office nearest the OCS facility or at other locations conveniently available to the District Manager. These documents must be made available to BSEE upon request and must be retained for the life of the facility. All approved designs are subject to field verifications.

[84 FR 24705, May 29, 2019]

§§ 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 §§ 250.851 through 250.872, in addition to the practices 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 supporting production operations must meet the requirements in the following table:

Item name	Applicable codes and requirements
(1) Pressure and fired vessels	(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 (incorporated by reference as specified in § 250.198). (ii) Must be repaired, maintained, and inspected in accordance with API 510 (incorporated by reference as specified in § 250.198).
(2) Existing uncoded pressure and fired vessels:	Must be justified and approval obtained from the District Manager for their continued use.
(i) With an operating pressure greater than 15 psig; and	
(ii) That are not code stamped in accordance with the ASME Boiler and Pressure Vessel Code	

Item name	Applicable codes and requirements
(3) 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 (incorporated by reference as specified in § 250.198). (ii) Must conform to the valve sizing and pressure-relieving requirements specified in these documents, but must be set no higher than the maximum-allowable working pressure of the vessel (except for cases where staggered set pressures are required for configurations using multiple relief valves or redundant valves installed and designated for operator use only). (iii) Vents must be positioned in such a way as to prevent fluid from striking personnel or ignition sources.
(4) 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.
(5) 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) Must be equipped with 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 that the normalized system pressure changes by 50 psig or 5 percent. Once system pressure has stabilized, pressure recording devices must be utilized to establish the new operating pressure ranges. The pressure recording devices must document the pressure range over time intervals that are no less than 4 hours and no more than 30 days long. 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 (initial set points for pressure sensors must be set utilizing gauge readings and engineering design):

Type of sensor	Settings	Additional requirements
(1) High pressure shut-in sensor,	Must be set 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.

[76 FR 64462, Oct. 18, 2011, as amended at 84 FR 24706, May 29, 2019]

§ 250.852 Flowlines/Headers.

(a) You must:

(1) 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) 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. The pressure recording devices must document the pressure range over time intervals that are no less than 4 hours and no more than 30 days long.

(3) 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 (initial set points for pressure sensors must be set using gauge readings and engineering design):

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 ensure 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 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 $1\frac{1}{2}$ times the maximum allowable pressure of the 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) certificate for the design methodology contained in that report to ensure that the manufacturer has complied with the requirements of ANSI/API Spec. 17J (incorporated by reference 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 ANSI/API Spec. 17J (incorporated by reference 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 on the platform 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 on the platform and locate it upstream of the BSDV.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49259, Sept. 28, 2018]

§ 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 where possible, depending on the type of vessel for which the level sensor is used.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49259, Sept. 28, 2018]

§ 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:

(1) Your buoy is clamped,

(2) Your auto slew mode is activated, and

(3) 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 non-restricted to enable the rapid actuation of the shutdown system. Electronic ESD stations must be wired as de-energize to trip circuits or as supervised circuits. Because of the key role of the ESD system in the platform safety system, all ESD components must be of high quality and corrosion resistant and stations must be uniquely identified. Only ESD stations at the boat landing may utilize a loop of breakable synthetic tubing in lieu of a valve or electric switch. This breakable loop is not required to be physically located on the boat landing, but must be accessible from a vessel adjacent to or attached to the facility.

(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 shut down the diesel engine in the event of runaway (*i.e.,* overspeed). 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 over pressurization. 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 A.4 and A.8 (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), 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 in the discharge piping of each compressor cylinder or case discharge.

(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 the suction side of a compressor must be diverted to the pipeline, diverted to a flare or vent in accordance with §§ 250.1160 or 250.1161, 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) Once system pressure has stabilized, you must use pressure recording devices to establish the new operating pressure ranges for compressor discharge sensors whenever the normalized system pressure changes by 50 psig or 5 percent, whichever is higher. The pressure recording devices must document the pressure range over time intervals that are no less than 4 hours and no more than 30 days long. You must 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.

(c) Pressure shut-in sensors must be set according to the following table (initial set points for pressure sensors must be set utilizing gauge readings and engineering design):

Type of sensor	Settings	Additional requirements

Type of sensor	Settings	Additional requirements
(1) PSH sensor,	Must be set 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	Must also be set 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.
(2) PSL sensor,	Must be set 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	

§ 250.859 Firefighting systems.

(a) On fixed facilities, to protect all areas where production-handling equipment is located, you must install firefighting systems that meet the requirements of this paragraph. You must install a firewater system consisting of rigid pipe with fire hose stations and/or fixed firewater monitors to protect all areas where production-handling equipment is located. Your firewater system must include installation of a fixed water spray system in enclosed well-bay areas where hydrocarbon vapors may accumulate.

(1) Your firewater system must conform to API RP 14G (incorporated by reference as specified in § 250.198).

(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. In addition:

(i) As of September 7, 2017, 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.

(ii) For electric-driven firewater pump drivers, to provide for a potential 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.

(iii) 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, in a prominent place on the facility, a diagram of the firefighting system showing the location of all firefighting equipment.

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

(5) You must obtain approval from the District Manager before installing any firefighting system.

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

(b) On floating facilities, to protect all areas where production-handling equipment is located, you must install a firewater system consisting of rigid pipe with fire hose stations and/or fixed firewater monitors. You must install a fixed water spray system in enclosed well-bay areas where hydrocarbon vapors may accumulate. Your firewater system must conform to the USCG requirements for firefighting systems on floating facilities.

(c) Except as provided in paragraph (c)(1) and (2) of this section, on fixed and floating facilities, if you are required to maintain a firewater system and the system becomes inoperable, you must shut-in your production operations while making the necessary repairs. For fixed facilities only, you may continue your production operations on a temporary basis while you make the necessary repairs, provided that:

(1) You request that the appropriate District Manager approve the use of a chemical firefighting system on a temporary basis (for a period up to 7 days) while you make the necessary repairs;

(2) If you are unable to complete repairs during the approved time period because of circumstances beyond your control, the District Manager may grant multiple extensions to your previously approved request to use a chemical firefighting system for periods up to 7 days each.

§ 250.860 Chemical firefighting system.

For fixed platforms:

(a) On 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, as long as you ensure that the unit is available on the platform when personnel are on board.

(1) A minor platform is a structure with zero to five completions and no more than one item of production processing equipment.

(2) An unmanned platform is one that is not attended 24 hours a day or one on which personnel are not quartered overnight.

(b) On major platforms and minor manned platforms, you may use a firefighting system using chemicals-only in lieu of a water-based system 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.

(1) A major platform is a structure with either six or more completions or zero to five completions with more than one item of production processing equipment.

(2) A minor platform is a structure with zero to five completions and no more than one item of production processing equipment.

(3) A manned platform is one that is attended 24 hours a day or one on which personnel are quartered overnight.

(c) On major platforms and minor manned platforms, to obtain approval to use a chemical-only fire prevention and control system in lieu of a water system under paragraph (b) of this section, 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. You must 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.

For the use of a chemical firefighting system on major and minor manned platforms, you must provide the following in your risk assessment . . .	Including . . .
	(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 visit, 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 contractors on the platform.
(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.

For the use of a chemical firefighting system on major and minor manned platforms, you must provide the following in your risk assessment . . .	Including . . .
	(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.

(d) On major or minor platforms, if BSEE has approved your request to use a chemical-only fire suppressant system in lieu of a water system under paragraphs (b) and (c) of this section, and if you make an insignificant change to your platform subsequent to that approval, you must document the change and maintain the documentation for the life of the facility at either the facility or nearest field office for BSEE review and/or inspection. Do not submit this documentation to the 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, you must submit a new request for approval, including an updated risk assessment if previously required, to the appropriate District Manager. You must maintain, for the life of the facility, the most recent documentation that you submitted to BSEE at the facility or nearest field office.

§ 250.861 Foam firefighting systems.

When you install foam firefighting systems as part of a firefighting system that protects production handling areas, 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 consistent with 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) Ensure that the quantity of concentrate meets design requirements, and that tanks or containers are kept full, with space allowed for expansion.

§ 250.862 Fire and gas-detection systems.

For production processing areas only:

(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.

(1) 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.

(2) Enclosed areas (e.g., buildings, living quarters, or doghouses) are defined as those areas confined on more than 4 of their 6 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.

(3) 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. A gas detection system is not required for living quarters and doghouses that do not contain a gas source and that are not located in a classified area.

(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), provided that, if compliance with any provision of those standards would be in conflict with applicable regulations of the U.S. Coast Guard, compliance with the U.S. Coast Guard regulations controls.

§ 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 for each 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 (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. Once system pressure has stabilized, pressure recording devices must be utilized to establish the new operating pressure ranges. The pressure recording devices must document the pressure range over time intervals that are no less than 4 hours and no more than 30 days long. 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.

(c) Pressure shut-in sensors must be set according to the following table (initial set points for pressure sensors must be set utilizing gauge readings and engineering design):

Type of sensor	Settings	Additional requirements
(1) PSH sensor	Must be no higher than 15 percent or 5 psi (whichever is greater) above the highest operating pressure of the discharge line	Must be set sufficiently below the maximum allowable working pressure of the discharge piping. The PSH must also be set 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.
(2) PSL sensor	Must be set 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	

(d) The PSL must be placed into service when the pump discharge pressure has risen above the PSL sensing point, or within 45 seconds of the pump coming into service, whichever is sooner.

(e) 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 $^1/_2$ 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.

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

(g) The pump maximum discharge pressure must be determined using the maximum possible suction pressure and the maximum power output of the driver as appropriate for the pump type and service.

§ 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) You must equip temporary quarters with all safety devices required by API RP 14C, Appendix C (incorporated by reference as specified in § 250.198). The District Manager must approve the safety system/safety devices associated with the temporary quarters prior to installation.

(b) The District Manager may require you to install a temporary firewater system for temporary quarters in production processing areas or other classified areas.

(c) Temporary equipment associated with the production process system, including equipment used for well testing and/or well clean-up, must be approved by the District Manager.

(d) The District Manager must approve temporary generators that would require a change to the electrical one-line diagram in § 250.842(a).

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49259, Sept. 28, 2018]

§ 250.868 Non-metallic piping.

On fixed OCS facilities, you may use non-metallic piping (such as that made from polyvinyl chloride, chlorinated polyvinyl chloride, and reinforced fiberglass) only in accordance with the requirements of § 250.841(b).

§ 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 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 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 (sight 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. 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) Adequate ventilation;

(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 SSSVs) 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 in paragraph (a)(3) of this section, 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) On all new production safety system installations, component process control devices and component safety devices must not be installed utilizing the same sensing points.

(f) All pneumatic control panels and computer based control stations must be labeled according to API RP 14C nomenclature.

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

(a) You may apply industry standard Class B, Class C, or Class B/C logic to applicable PSL sensors installed on process equipment. If the device may be bypassed for greater than 45 seconds, you must monitor the bypassed devices in accordance with § 250.869(a). You must document on your field test records any 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). If a Class C safety device is bypassed, you must monitor the device until it is in full service.

(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.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49259, Sept. 28, 2018]

§ 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.

§ 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 in § 250.198) with protective equipment identified in API RP 14C, section A.5 (incorporated by reference in § 250.198). Transport tanks approved by the U.S. Department of Transportation, that are sealed and not connected via interconnected piping to the production process train and that are used only for storage of refined liquid hydrocarbons or Class I liquids, are not required to be equipped with the protective equipment identified in API RP 14C, section A.5. The atmospheric vessels connected to the process system that contains a Class I liquid and the associated pumps must be reflected on the design documents listed in § 250.842(a)(1) through (4) and (b)(3).

(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.

(c) You must ensure that all atmospheric vessels are designed, installed, and maintained to prevent pollution, including the displacement of oil out of an overboard water outlet, as required by § 250.300(b)(3) and (4).

[83 FR 49259, Sept. 28, 2018]

§ 250.873 Subsea gas lift requirements.

If you choose to install a subsea gas lift system, you must design your system as approved in your DWOP or as follows:

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

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

If your subsea gas lift system introduces the lift gas to the . . .	Then you must install a				In addition, you must
	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 . . .	

If your subsea gas lift system introduces the lift gas to the . . .	Then you must install a				In addition, you must
	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 or umbilical	Meet all of the requirements for the BSDV described in §§ 250.835 and 250.836 on the gas-lift supply pipeline. Locate the GLSDV within 10 feet of the first point 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	(i) Ensure that the MAOP of a subsea gas lift supply pipeline is equal to the MAOP of the production pipeline. (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. (iii) Install the GLIV downstream of the underwater safety valve(s) (USV) and/or AIV(s).

If your subsea gas lift system introduces the lift gas to the . . .	Then you must install a				In addition, you must
	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 . . .	
(2) Subsea well(s) through the casing string via an external gas lift pipeline or umbilical	Meet all of the requirements for the GLSDV described in §§ 250.835 and 250.836 on the gas-lift supply pipeline. Locate the GLSDV within 10 feet of the first point 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 down-stream (out board) of the GLSDV	downstream (out board) of the PSHL and above the waterline. This valve does not have to be actuated.	(i) 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. (ii) If your subsea tree 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. (iii) 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				In addition, you must
	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	Meet all of the requirements for the GLSDV described in §§ 250.835(a), (b), and (d) and 250.836 on the gas-lift supply pipeline	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.
	Attach the GLSDV by flanged connection directly to the ANSI/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 ANSI/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 ANSI/API Spec. 6A component used to suspend and seal the gas-lift line contained within the production riser				(ii) Ensure that any surface equipment associated with the gas-lift system is rated for the MAOP of the pipeline riser. (iii) Ensure that the gas-lift compressor discharge pressure never exceeds the MAOP of the pipeline riser. (iv) Suspend and seal the gas-lift flowline contained within the production riser in a flanged ANSI/API

If your subsea gas lift system introduces the lift gas to the . . .	Then you must install a				In addition, you must
	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 . . .	
					Spec. 6A component such as an ANSI/API Spec. 6A tubing head and tubing hanger or a component designed, constructed, tested, and installed to the requirements of ANSI/API Spec. 6A. (v) 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. (vi) Ensure that this complete assembly is fire-rated for 30 minutes.

(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 system valve testing requirements according to the following table:

Type of gas lift system	Valve	Allowable leakage rate	Testing frequency
(1) 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.
(2) 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
(3) Gas lifting the pipeline riser via a gas lift line contained within the pipeline riser	GLSDV	Zero leakage	Monthly, not to exceed 6 weeks.

[76 FR 64462, Oct. 18, 2011, as amended at 84 FR 24707, May 29, 2019]

§ 250.874 Subsea water injection systems.

If you choose to install a subsea water injection system, your system must comply with your approved DWOP, which must meet the following minimum requirements:

(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 self-activated 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) Use subsea tree(s), wellhead(s), connector(s), and tree valves, and surface-controlled SSSV or WIV associated with a water injection system that are rated for the maximum anticipated injection pressure.

(e) Consider the effects of hydrogen sulfide (H2S) when designing your water flood system, as required by § 250.805.

(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, and

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

(g) Comply with the following injection valve testing requirements:

(1) You must test your injection valves as provided in the following table:

Valve	Allowable leakage rate	Testing frequency

Valve	Allowable leakage rate	Testing frequency
(i) WISDV	Zero leakage	Monthly, not to exceed 6 weeks between tests.
(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 between tests.

(2) If a designated USV on a water injection well fails the applicable test under § 250.880(c)(4)(ii), you must notify the appropriate District Manager and request approval to designate another ANSI/API Spec 6A and API Spec. 6AV1 (both incorporated by reference in § 250.198) certified subsea valve as your USV.

(3) If a USV on a water injection well fails the test and the surface-controlled SSSV or WIV cannot be tested as required under (g)(1)(ii) of this section because of low reservoir pressure, you must submit a request to the appropriate District Manager with an alternative plan that ensures subsea shutdown capabilities.

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

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

(2) Obtain approval from the appropriate District Manager to continue to inject during the loss of communication.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49262, Sept. 28, 2018]

§ 250.875 Subsea pump systems.

If you choose to install a subsea pump system, your system must comply with your approved DWOP, which must meet the following minimum requirements:

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

(b) Include 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) 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) Include, at minimum, 2 independent functioning PSHL sensors upstream of the subsea pump and 2 independent functioning PSHL sensors downstream of the pump, that:

(i) Are operational when the subsea pump is in service; and

(ii) Will, when activated, 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 2 PSHL sensors are installed both upstream and downstream of the subsea pump for operational flexibility, then 2 out of 3 voting logic may be implemented in which the subsea pump remains operational provided a minimum of 2 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 at a minimum 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 parameters associated with the subsea pump operation (e.g., pump temperature high, pump vibration high, pump suction pressure high, pump discharge pressure high, pump suction flow low) must be cleared (*i.e.,* within operational limits) or continuously monitored by personnel who 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 communication with the subsea well(s) and not a loss of communication with the subsea pump control system without an ESD or sensor activation;

(3) A loss of communication with the subsea pump control system, and not a loss of communication with the subsea well(s);

(4) A loss of communication with the subsea well(s) and the subsea pump control system.

(e) For subsea pump testing:

(1) Perform 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) Test the subsea pump shutdown, including PSHL sensors both upstream and downstream of the pump, each quarter (not to exceed 120 days between tests). This testing may be performed concurrently with the ESD function test required by § 250.880(c)(4)(v).

§ 250.876 Fired and exhaust heated components.

No later than September 7, 2018, and at least once every 5 years thereafter, you must have qualified third-party inspect, and then you must repair or replace, as needed, the fire tube for 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 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 the documentation available to BSEE upon request.

[83 FR 49262, Sept. 28, 2018]

§§ 250.877-250.879 [Reserved]

Safety Device Testing

§ 250.880 Production safety system testing.

(a) ***Notification.*** You must:

(1) Notify the District Manager at least 72 hours before you commence initial production on a facility as required in § 250.800(a)(2), in order for BSEE to conduct the 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 specified in the table set forth in paragraph (c)(4) of this section.

(b) ***Testing methodologies.*** You must:

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

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

(c) ***Testing frequencies.*** You must:

(1) Comply with the following testing requirements for 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)	Semi-annually, not to exceed 6 calendar months between tests. 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 standard cubic feet per minute is observed, the device must be removed, repaired, and reinstalled or replaced. Testing must be according to ANSI/API RP 14B (incorporated by reference in § 250.198) to ensure proper operation.
(ii) Subsurface-controlled SSSVs	Semi-annually, not to exceed 6 calendar months between tests 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	Semi-annually, not to exceed 6 calendar months between tests. Test by opening the well to possible flow. If a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 standard 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	Semi-annually, not to exceed 6 calendar months between tests. Test by opening the well to possible flow. If a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 standard cubic feet per minute is observed, the valve must be removed, repaired and reinstalled or replaced.

(2) Comply with the following testing requirements for surface valves:

Item name	Testing frequency and requirements
(i) PSVs	Annually, not to exceed 12 calendar 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. The main valve piston must be lifted during this test.

Item name	Testing frequency and requirements
(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 STD 6AV2 (incorporated by reference in § 250.198). If an SSV does not operate properly or if any gas and/or liquid fluid flow is observed during the leakage test, the valve must be immediately repaired or replaced.
(v) Flowline FSVs	Once each calendar month, not to exceed 6 weeks between tests. All flowline FSVs must be tested, including those installed on a host facility in lieu of being installed at a satellite well. You must test flowline FSVs for leakage in accordance with the test procedure specified in API RP 14C (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 standard cubic feet per minute, the FSV must be repaired or replaced.

(3) Comply with the following testing requirements for 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) and gas detection systems	Must be tested for operation and recalibrated every 3 months, not to exceed 120 days between tests, 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.

Item name	Testing frequency and requirements
(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. All stations must be checked for functionality at least once each calendar month, not to exceed 6 weeks between tests. No station may be reused until all stations have been tested. (B) Electronic based ESD systems must be tested for operation at least once every 3 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. All stations must be checked for functionality at least once every 3 calendar months, not to exceed 120 days between checks. No station may be reused until all stations have been tested. (C) Electronic/pneumatic based ESD systems must be tested for operation at least once every 3 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. All stations must be checked for functionality at least once every 3 calendar months, not to exceed 120 days between checks. No station may be reused until all stations have been used.
(iv) TSH devices	Must be tested for operation annually, not to exceed 12 calendar months between tests, excluding those addressed in paragraph (c)(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 annually, not to exceed 12 calendar months between tests.
(vii) Flow safety low devices	Must be tested annually, not to exceed 12 calendar months between tests.
(viii) Flame, spark, and detonation arrestors	Must be visually inspected annually, not to exceed 12 calendar months between inspections.

Item name	Testing frequency and requirements
(ix) Electronic pressure transmitters and level sensors: PSH and PSL; LSH and LSL	Must be tested at least once every 3 months, not to exceed 120 days 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, not to exceed 6 weeks between tests.

(4) Comply with the following testing requirements for 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 between tests. If the device does not operate properly, or if a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 standard cubic feet per minute is observed, the device must be removed, repaired, and reinstalled or replaced. Testing must be according to ANSI/API RP 14B (incorporated by reference in § 250.198) to ensure proper operation, or as approved in your DWOP.
(ii) USVs	Tested at least once every 3 calendar months, not to exceed 120 days between tests. If the device does not function properly, or if a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 standard cubic feet per minute is observed, the valve must be removed, repaired, and reinstalled or replaced.
(iii) BSDVs	Tested at least 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 STD 6AV2 for SSVs (incorporated by reference 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 at least once each calendar month, not to exceed 6 weeks between tests.
(v) Electronic ESD function	Tested at least once every 3 calendar months, not to exceed 120 days between tests. 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.

(d) ***Subsea wells.***

(1) Any subsea well that is completed and disconnected from monitoring capability may not be disconnected for more than 24 months, unless authorized by BSEE.

(2) Any subsea well that is completed and disconnected from monitoring capability for more than 6 months must meet the following testing and other requirements:

(i) Each well must have 3 pressure barriers:

(A) A closed and tested surface-controlled SSSV,

(B) A closed and tested USV, and

(C) One additional closed and tested tree valve.

(ii) For new completed wells, prior to the rig leaving the well, the pressure barriers must be tested 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 rate.

(iii) A sealing pressure cap must be installed on the flowline connection hub until the flowline is installed and connected. The pressure cap must be designed to accommodate monitoring for pressure between the production wing valve and cap. The pressure cap must also be designed so that a remotely operated vehicle can bleed pressure off, monitor for buildup, and confirm 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 of the pressure barrier (prior to demobilizing the rig from the field).

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

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49262, Sept. 28, 2018]

§§ 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 facilities at least annually or when contact information is revised. The contact list must include:

(1) Designated operator name;

(2) Designated primary point of contact for the facility;

(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 O and subpart S of this part.

§§ 250.892-250.899 [Reserved]