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DEPARTMENT OF THE INTERIOR

Bureau of Safety and Environmental Enforcement

30 CFR Part 250

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RIN 1014–AA10

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

Correction

In proposed rule document 2013-19861, appearing on pages 52240 through 52284 in the issue of Thursday, August 22, 2013, make the following corrections:

1. On pages 52241 through 52242, the table should read as follows:

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

Current regulation	Proposed Rule
	§ 250.827 Surface-controlled SSSVs – subsea trees.
	§ 250.828 Design, installation, and operation of SSSVs – subsea trees.
	§ 250.829 Subsurface safety devices in shut-in wells – subsea trees.
	§ 250.830 Subsurface safety devices in injection wells – subsea trees.
	§ 250.832 Additional safety equipment – subsea trees.
	§ 250.837 Emergency action and safety system shutdown.
§ 250.802 Design, installation, and operation of surface production-safety systems.	§ 250.819 Specification for surface safety valves (SSVs).
	§ 250.820 Use of SSVs.
	§ 250.833 Specification for underwater safety valves (USVs).
	§ 250.834 Use of USVs.
	§ 250.840 Design, installation, and maintenance - general.
	§ 250.841 Platforms.
	§ 250.842 Approval of safety systems design and installation features.
§ 250.803 Additional production system requirements.	§ 250.850 Production system requirements - general.
	§ 250.851 Pressure vessels (including heat exchangers) and fired vessels.
	§ 250.852 Flowlines/Headers.
	§ 250.853 Safety sensors.
	§ 250.855 Emergency shutdown (ESD) system.
	§ 250.856 Engines.
	§ 250.857 Glycol dehydration units.
	§ 250.858 Gas compressors.
	§ 250.859 Firefighting systems.
	§ 250.862 Fire and gas-detection systems.
	§ 250.863 Electrical equipment.
	§ 250.864 Erosion.
	§ 250.869 General platform operations.
	§ 250.871 Welding and burning practices and procedures.
§ 250.804 Production safety-system testing and records.	§ 250.880 Production safety system testing.
	§ 250.890 Records.
§ 250.805 Safety device training.	§ 250.891 Safety device training.
§ 250.806 Safety and pollution prevention equipment quality assurance requirements.	§ 250.801 Safety and pollution prevention equipment (SPPE) certification.
	§ 250.802 Requirements for SPPE.
§ 250.807 Additional requirements for subsurface safety valves and related equipment installed in high pressure high temperature (HPHT)	§ 250.804 Additional requirements for subsurface safety valves (SSSVs) and related equipment installed in high pressure high temperature

Current regulation	Proposed Rule
environments.	(HPHT) environments.
§ 250.808 Hydrogen sulfide.	§250.805 Hydrogen sulfide.
New Sections	§250.803 What SPPE failure reporting procedures must I follow?
	§ 250.831 Alteration or disconnection of subsea pipeline or umbilical.
	§ 250.835 Specification for all boarding shut down valves (BSDV) associated with subsea systems.
	§ 250.836 Use of BSDVs
	§ 250.838 What are the maximum allowable valve closure times and hydraulic bleeding requirements for an electro-hydraulic control system?
	§ 250.839 What are the maximum allowable valve closure times and hydraulic bleeding requirements for a direct-hydraulic control system?
	§ 250.854 Floating production units equipped with turrets and turret mounted systems.
	§ 250.860 Chemical firefighting system.
	§ 250.861 Foam firefighting system.
	§ 250.865 Surface pumps.
	§ 250.866 Personal safety equipment.
	§ 250.867 Temporary quarters and temporary equipment.
	§ 250.868 Non-metallic piping.
	§ 250.870 Time delays on pressure safety low (PSL) sensors.
	§ 250.872 Atmospheric vessels.
	§ 250.873 Subsea gas lift requirements.
	§ 250.874 Subsea water injection systems.
	§ 250.875 Subsea pump systems.
	§ 250.876 Fired and Exhaust Heated Components.

2. On page 52251, the table should read as follows:

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

Injection valves.	liquid leakage rate < 200 cubic centimeters per minute, or gas leakage rate < 5 cubic feet per minute.	liquid leakage rate < 400 cubic centimeters per minute, or gas leakage rate < 15 cubic feet per minute.
USVs.	0 leakage rate.	liquid leakage rate < 400 cubic centimeters per minute, or gas leakage rate < 15 cubic feet per minute.
Flow safety valves (FSV).	liquid leakage rate < 200 cubic centimeters per minute, or gas leakage rate < 5 cubic feet per minute.	liquid leakage rate < 400 cubic centimeters per minute, or gas leakage rate < 15 cubic feet per minute.

3. On page 52254, Table 2 should read as follows:

Table 2: ANNUAL COST PER SMALL ENTITY (10-YEAR AVERAGE)[1]

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

[1] Totals may not add because of rounding.

4. On pages 52256 through 52260, the table should read as follows:

Citation 30 CFR 250, Subpart A	**Reporting and Recordkeeping Requirement**	**Hour Burden**	**Average No. of Annual Responses**	**Annual Burden Hours**
107(c)(2)	**NEW:** Demonstrate to us that by using BAST the benefits are insufficient to justify the cost.	5	2 justifications	10
Subtotal			**2 responses**	**10 hours**
Citation 30 CFR 250 Subpart H and NTL(s)	**Reporting and Recordkeeping Requirement**	**Hour Burden**	**Average No. of Annual Responses**	**Annual Burden Hours**
		Non-Hour Cost Burdens*		
General Requirements				

800(a)	Requirements for your production safety system application.	Burden included with specific requirements below.		0
800(a); 880(a);	Prior to production, request approval of pre-production inspection; notify BSEE 72 hours before commencement so we may witness preproduction test and conduct inspection.	1	76 requests	76
801(c)	Request evaluation and approval [OORP] of other quality assurance programs covering manufacture of SPPE.	2	1 request	2
802(c)(1); 852(e)(4); 861(b);	**NEW:** Submit statement/certification for: exposure functionality; pipe is suitable and manufacturer has complied with IVA; suitable firefighting foam per original manufacturer specifications.	Not considered IC under 5 CFR 1320.3(h)(1).		0
802(c)(5)	**NEW:** Document all manufacturing, traceability, quality control, and inspection requirements. Retain required documentation until 1 year after the date of decommissioning the equipment.	2	30 documents	60
803(a)	**NEW:** Within 30 days of discovery and identification of SPPE failure, provide a written report of equipment failure to manufacturer.	2	10 reports	20
803(b)	**NEW:** Document and determine the results of the SPPE failure within 60-days and corrective action taken.	5	10 documents	50
803(c)	**NEW:** Submit [OORP] modified procedures you made if notified by manufacturer of design changes or you changed operating or repair procedures as result of a failure, within 30 days.	2	1 submittal	2
804	Submit detailed info regarding installing SSVs in an HPHT environment with your APD, APM, DWOP etc.	Burdens are covered under 30 CFR 250, Subparts D and B, 1014-0018 and 1014-0024.		0
804(b); 829(b), (c); 841(b);	**NEW:** District Manager will approve on a case-by-case basis.	Not considered IC per 5 CFR 1320.3(h)(6).		0
		Subtotal	**128 responses**	**210 hours**
		Surface and Subsurface Safety Systems – Dry Trees		
810; 816; 825(a); 830;	Submit request for a determination that a well is incapable of natural flow.	5 ¾	41wells	246
	Verify the no-flow condition of the well annually.	¼		
814(a); 821; 828(a); 838(c)(3); 859(b); 870(b);	Specific alternate approval requests requiring approval.	Burden covered under 30 CFR 250, subpart A, 1014-0022.		0
817(b); 869(a);	Identify well with sign on wellhead that sub-surface safety device is removed; flag safety devices that are out of service; a visual indicator must be used to identify the	Usual/customary safety procedure for removing or identifying out-of-service safety devices.		0

	bypassed safety device.			
817(b)	Record removal of subsurface safety device.	Burden included in § 250.890 of this subpart.		0
817(c)	Request alternate approval of master valve [required to be submitted with an APM].	Burden covered under 30 CFR 250, subpart D, 1014-0018.		0
		Subtotal	**41 responses**	**246 hours**
	Subsea and Subsurface Safety Systems – Subsea Trees			
825(b); 831; 833; 837(c)(5); 838(c); 874(g)(2); 874(f);	**NEW:** Notify BSEE: (1) if you cannot test all valves and sensors; (2) 48 hours in advance if monitoring ability affected; (3) designating USV2 or another qualified valve; (4) resuming production; (5) 12 hours of detecting loss of communication; immediately if you cannot meet value closure conditions.	Notifications (1) ½ (2) 2 (3) 1 (4) ½ (5) ½	 6 1 1 1 1	7
827	**NEW:** Request remote location approval.	1	1 request	1
831	**NEW:** Submit a repair/replacement plan to monitor and test.	2	1 submittal	2
837(a)	**NEW:** Request approval to not shut-in a subsea well in an emergency.	½	10 requests	5
837(b)	**NEW:** Prepare and submit for approval a plan to shut-in wells affected by a dropped object.	2	1 submittal	2
837(c)(2)	**NEW:** Obtain approval to resume production re P/L PSHL sensor.	½	2 approvals	1
838(a); 839(a)(2);	**NEW:** Verify closure time of USV upon request of District Manager.	2	2 verifications	4
838(c)(3)	**NEW:** Request approval to produce after loss of communication; include alternate valve closure table.	2	1 approval	2
		Subtotal	**28 responses**	**24 hours**
	Production Safety Systems			
842;	Submit application, and all required/supporting information, for a production safety system with > 125 components.	16	1 application	16
		$5,030 per submission x 1 = $5,030 $13,238 per offshore visit x 1 = $13,238 $6,884 per shipyard visit x 1 = $6,884		
	25 – 125 components.	13	10 applications	130
		$1,218 per submission x 10 = $12,180 $8,313 per offshore visit x 1 = $8,313 $4,766 per shipyard visit x 1 = $4,766		
	< 25 components.	8	20 applications	160
		$604 per submission x 20 = $12,080		
	Submit modification to application for production safety system with > 125 components.	9	180 modifications	1,620
		$561 per submission x 180 = $100,980		
	25 – 125 components.	7	758 modifications	5,306
		$201 per submission x 758 = $152,358		
	< 25 components.	5	329 modifications	1,645
		$85 per submission x 329 = $27,965		

842(b)	**NEW:** Your application must also include certification(s) that the designs for mechanical and electrical systems were reviewed, approved, and stamped by registered professional engineer. [NOTE: Upon promulgation, these certification production safety systems requirements will be consolidated into the application hour burden for the specific components.]	6	32 certifications	192
842(c)	**NEW:** Submit a certification letter that the mechanical and electrical systems were installed in accordance with approved designs.	6	32 letters	192
842(d), (e);	**NEW:** Submit a certification letter within 60-days after production that the as-built diagrams, piping, and instrumentation diagrams are on file, certified correct, and stamped by a registered professional engineer; submit all the as-built diagrams.	6 ½	32 letters	208
842(f)	**NEW:** Maintain records pertaining to approved design and installation features and as-built pipe and instrumentation diagrams at your offshore field office or location available to the District Manager; make available to BSEE upon request and retained for the life of the facility.	½	32 records	16
		Subtotal	**1,426 responses**	**9,485 hours**
			$343,794 non-hour cost burdens	
	Additional Production System Requirements			
851(a)(4)	**NEW:** Request approval to use uncoded pressure and fired vessels beyond their 18 months of continued use.	2	1 request	2
851(b); 852(a)(3); 858(c); 865(b);	Maintain [most current] pressure-recorder information at location available to the District Manager for as long as information is valid.	23	615 records	14,145
851(c)(2)	**NEW:** Request approval from District Manager for activation limits set less than 5 psi.	1	10 requests	10
852(c)(1)	**NEW:** Request approval from District Manager to vent to some other location.	1	10 requests	10
852(c)(2)	**NEW:** Request a different sized PSV.	1	1 request	5
852(c)(2)	**NEW:** Request different upstream location of the PSV.	1	5 request	5
852(e)	Submit required design documentation for unbonded flexible pipe.	Burden is covered by the application requirement in § 250.842.		0
855(b)	Maintain ESD schematic listing control function of all safety devices at location conveniently available to the District Manager for the life of the facility.	15	615 listings	9,225
858(b)	**NEW:** Request approval from District Manager to use different procedure for gas-	1	1 request	1

	well gas affected.			
859(a)(2)	Request approval for alternate firefighting system.	Burden covered under 30 CFR 250, subpart A, 1014-0022.		0
859(a)(3), (4)	Post diagram of firefighting system; furnish evidence firefighting system suitable for operations in subfreezing climates.	5	38 postings	190
859(b)	**NEW:** Request extension from District Manager up to 7 days of your approved departure to use chemicals.	Burden covered under 30 CFR 250, subpart A, 1014-0022.		0
860(a); related NTL(s)	Request approval, including but not limited to, submittal of justification and risk assessment, to use chemical only fire prevention and control system in lieu of a water system.	22	31 requests	682
860(b)	**NEW:** Minor change(s) made after approval rec'd re 860(a) - document change; maintain the revised version at facility or closest field office for BSEE review/inspection; maintain for life of facility.	½	10 minor changes	5
860(b)	**NEW:** Major change(s) made after approval rec'd re 860(a) - submit new request w/updated risk assessment to District Manager for approval; maintain at facility or closest field office for BSEE review/inspection; maintain for life of facility.	2	1 major change	2
861(b)	**NEW:** Submit foam concentrate samples annually to manufacturer for testing.	2	500 submittals	1,000
864	Maintain erosion control program records for 2 years; make available to BSEE upon request.	12	615 records	7,380
867(a)	**NEW:** Request approval from District Manager to install temporary quarters.	6	1 request	6
867(b)	**NEW:** Submit supporting information/documentation if required by District Manager to install a temporary firewater system.	1	1 request	1
867(c)	**NEW:** Request approval form District manager to use temporary equipment for well testing/clean-up.	1	300 requests	300
869(a)(3)	**NEW:** Request approval from District Manager to bypass an element of ESS.	1	2 requests	2
870	**NEW:** Document PSL on your field test records w/delay greater than 45 seconds.	½	6 records	3
871	Request variance from District Manager on approved welding and burning practices.	Burden covered under 30 CFR 250, subpart A – 1014-0022.		0
874(g)(2), (3)	**NEW:** Submit request to District Manager with alternative plan ensuring subsea shutdown capability.	2	5 requests	10
874(g)(3)	**NEW:** Request approval from District Manager to forgo WISDV testing.	1	10 requests	10
874(f)(2)	**NEW:** Request approval from District Manager to continue to inject w/loss of	1	5 requests	5

	communication.			
874(f)(2)	**NEW:** Request alternate hydraulic bleed schedule.	Burden covered under 30 CFR 250, subpart A, 1014-0022.		0
		Subtotal	**2,783 responses**	**32,999 hours**
		Safety Device Testing		
880(a)(3)	**NEW:** Notify BSEE and receive approval before performing modifications to existing subsea infrastructure.	Burden covered under 30 CFR 250, subpart A 1014-0022.		0
880(c)(5)(vi)	**NEW:** Request approval for disconnected well shut-in to exceed more than 2 years.	1	1 request	1
		Subtotal	**1 response**	**1 hour**
		Records and Training		
890	Maintain records for 2 years on subsurface and surface safety devices to include, but limited to, status and history of each device; approved design & installation date and features, inspection, testing, repair, removal, adjustments, reinstallation, etc.; at field office nearest facility AND a secure onshore location; make records available to BSEE.	36	615 records	22,140
890(c)	**NEW:** Submit annually to District Manager a contact list for all OCS operated platforms or submit when revised.	½	1,000 annual lists	550
		½	100 revised lists	
		Subtotal	**1,715 responses**	**22,690 hours**
Total Burden Hours			**6,124 Responses**	**65,665 Hours**
			$343,794 Non-Hour Cost Burdens	

5. On page 52271, the table should read as follows:

You must submit:	**Details and/or additional requirements:**
(1) A schematic piping and instrumentation diagram…	Showing the following: (i) Well shut-in tubing pressure; (ii) Piping specification breaks, piping sizes; (iii) Pressure relief valve set points; (iv) Size, capacity, and design working pressures of separators, flare scrubbers, heat exchangers, treaters, storage tanks, compressors and metering devices; (v) Size, capacity, design working pressures, and maximum discharge pressure of hydrocarbon-handling pumps; (vi) size, capacity, and design working pressures of hydrocarbon-handling vessels, and chemical injection systems handling a material having a flash point below 100 degrees Fahrenheit for a Class I flammable liquid as described in API RP 500 and 505 (both incorporated by reference as specified in § 250.198). (vii) Size and maximum allowable working

	pressures as determined in accordance with API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems (incorporated by reference as specified in § 250.198).
(2) A safety analysis flow diagram (API RP 14C, Appendix E) and the related Safety Analysis Function Evaluation (SAFE) chart (API RP 14C, subsection 4.3.3) (incorporated by reference as specified in § 250.198)…	if processing components are used, other than those for which Safety Analysis Checklists are included in API RP 14C, you must use the same analysis technique and documentation to determine the effects and requirements of these components upon the safety system.
(3) Electrical system information, including …	(i) A plan for each platform deck and outlining all classified areas. You must classify areas according to API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2; or API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2 (both incorporated by reference as specified in § 250.198). (ii) Identification of all areas where potential ignition sources, including non-electrical ignition sources, are to be installed showing: (A) All major production equipment, wells, and other significant hydrocarbon sources, and a description of the type of decking, ceiling, and walls (*e.g.*, grating or solid) and firewalls and; (B) the location of generators, control rooms, panel boards, major cabling/conduit routes, and identification of the primary wiring method (*e.g.*, type cable, conduit, wire) and; (iii) one-line electrical drawings of all electrical systems including the safety shutdown system. You must also include a functional legend.
(4) Schematics of the fire and gas-detection systems…	showing a functional block diagram of the detection system, including the electrical power supply and also including the type, location, and number of detection sensors; the type and kind of alarms, including emergency equipment to be activated; the method used for detection; and the method and frequency of calibration.
(5) The service fee listed in § 250.125.	The fee you must pay will be determined by the number of components involved in the review and approval process.

6. On page 52272, the table should read as follows:

Item name	**Applicable codes and requirements**
(1) Pressure and fired vessels	(i) Must be designed, fabricated, and code stamped according to

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

7. On pages 52275 through 52276, the table should read as follows:

For the use of a chemical firefighting system on major and minor manned platforms, you must provide the following in your risk assessment…	**Including…**
(i) Platform description	(A) The type and quantity of hydrocarbons (*i.e.,* natural gas, oil) that are produced, handled, stored, or processed at the facility. (B) The capacity of any tanks on the facility that you use to store either liquid hydrocarbons or other flammable liquids.

	(C) The total volume of flammable liquids (other than produced hydrocarbons) stored on the facility in containers other than bulk storage tanks. Include flammable liquids stored in paint lockers, storerooms, and drums. (D) If the facility is manned, provide the maximum number of personnel on board and the anticipated length of their stay. (E) If the facility is unmanned, provide the number of days per week the facility will be visited, the average length of time spent on the facility per day, the mode of transportation, and whether or not transportation will be available at the facility while personnel are on board. (F) A diagram that depicts: quarters location, production equipment location, fire prevention and control equipment location, lifesaving appliances and equipment location, and evacuation plan escape routes from quarters and all manned working spaces to primary evacuation equipment.
(ii) Hazard assessment (facility specific)	(A) Identification of all likely fire initiation scenarios (including those resulting from maintenance and repair activities). For each scenario, discuss its potential severity and identify the ignition and fuel sources. (B) Estimates of the fire/radiant heat exposure that personnel could be subjected to. Show how you have considered designated muster areas and evacuation routes near fuel sources and have verified proper flare boom sizing for radiant heat exposure.
(iii) Human factors assessment (not facility specific)	(A) Descriptions of the fire-related training your employees and contractors have received. Include details on the length of training, whether the training was hands-on or classroom, the training frequency, and the topics covered during the training. (B) Descriptions of the training your employees and contractors have received in fire prevention, control of ignition sources, and control of fuel sources when the facility is occupied. (C) Descriptions of the instructions and procedures you have given to your employees and contractors on the actions they should take if a fire occurs. Include those instructions and procedures specific to evacuation. State how you convey this information to your employees and contractor on the platform.
(iv) Evacuation assessment (facility specific)	(A) A general discussion of your evacuation plan. Identify your muster areas (if applicable), both the primary and secondary evacuation routes, and the means of evacuation for both. (B) Description of the type, quantity, and location of lifesaving appliances available on the facility. Show how you have ensured that lifesaving appliances are located in the near vicinity of the escape routes. (C) Description of the types and availability of support vessels, whether the support vessels are equipped with a fire monitor, and the time needed for support vessels to arrive at the facility. (D) Estimates of the worst case time needed for personnel to evacuate the facility should a fire occur.
(v) Alternative protection assessment	(A) Discussion of the reasons you are proposing to use an alternative fire prevention and control system. (B) Lists of the specific standards used to design the system, locate the equipment, and operate the equipment/system. (C) Description of the proposed alternative fire prevention and control system/equipment. Provide details on the type, size, number, and location of the prevention and control equipment.

	(D) Description of the testing, inspection, and maintenance program you will use to maintain the fire prevention and control equipment in an operable condition. Provide specifics regarding the type of inspection, the personnel who conduct the inspections, the inspection procedures, and documentation and recordkeeping.
(vi) Conclusion	A summary of your technical evaluation showing that the alternative system provides an equivalent level of personnel protection for the specific hazards located on the facility.

8. On pages 52279 through 52280, the table spanning those two pages should read as follows:

If your subsea gas lift system introduces the lift gas to the…	**Then you must install a...**				**Additional requirements**
	API Spec 6A and API Spec 6AV1 (both incorporated by reference as specified in § 250.198) gas-lift shutdown valve (GLSDV), and…	**FSV on the gas-lift supply pipeline…**	**PSHL on the gas-lift supply...**	**API Spec 6A and API Spec 6AV1 manual isolation valve…**	
(1) Subsea Pipelines, Pipeline Risers, or Manifolds via an External Gas Lift Pipeline	meet all of the requirements for the BSDV described in 250.835 and 250.836 on the gas-lift supply pipeline.	upstream (in board) of the GLSDV	pipeline upstream (in board) of the GLSDV	downstream (out board) of the PSHL and above the waterline. This valve does not have to be actuated.	(i) Ensure that the MAOP of a subsea gas lift supply pipeline is equal to the MAOP of the production pipeline. an actuated fail-safe close gas-lift isolation valve (GLIV) located at the point of intersection between the gas lift supply pipeline and the production pipeline, pipeline riser, or manifold. (ii) Install an actuated fail-safe close gas-lift isolation valve (GLIV) located at the point of intersection between the gas lift supply pipeline and the production pipeline, pipeline riser, or manifold. Install the GLIV downstream of the underwater safety valve(s) (USV) and/or AIV(s).

(2) Subsea Well(s) through the Casing String via an External Gas Lift Pipeline.	Locate the GLSDV within 10 feet of the first of access to the gas-lift riser or topsides umbilical termination assembly (TUTA) (i.e., within 10 feet of the edge of the platform if the GLSDV is horizontal, or within 10 feet above the first accessible working deck, excluding the boat landing and above the splash zone, if the GLSDV is in the vertical run of a riser, or within 10 feet of the TUTA if using an umbilical).	on the platform upstream (in board) of the GLSDV	pipeline on the platform downstream (out board) of the GLSDV.	downstream (out board) of the PSHL and above the waterline. This valve does not have to be actuated.	Install an actuated, fail-safe-closed GLIV on the gas lift supply pipeline near the wellhead to provide the dual function of containing annular pressure and shutting off the gas lift supply gas. If your subsea trees or tubing head is equipped with an annulus master valve (AMV) or an annulus wing valve (AWV), one of these may be designated as the GLIV. Consider installing the GLIV external to the subsea tree to facilitate repair and or replacement if necessary.
(3) Pipeline Risers via a Gas-Lift Line Contained within the Pipeline Riser	locate the GLSDV within 10 feet of the first of access to the gas-lift riser or TUTA (i.e., within 10 feet of the edge of the platform if the GLSDV is horizontal, or within 10 feet above the first accessible working deck, excluding the boat landing and above the splash zone, if the GLSDV is in the vertical run of a riser, or within 10 feet of the TUTA if using an umbilical).	upstream (in board) of the GLSDV	flowline upstream (in board) of the FSV.	downstream (out board) of the GLSDV.	(i) Ensure that the gas-lift supply flowline from the gas-lift compressor to the GLSDV is pressure-rated for the MAOP of the pipeline riser. Ensure that any surface equipment associated with the gas-lift system is rated for the MAOP of the pipeline riser. (ii) Ensure that the gas-lift compressor discharge pressure never exceeds the MAOP of the pipeline riser. (iii) Suspend and seal the gas-lift flowline contained within the production riser in a flanged API Spec. 6A component such as an API Spec. 6A tubing head and

					tubing hanger or a component designed, constructed, tested, and installed to the requirements of API Spec. 6A. Ensure that all potential leak paths upstream or near the production riser BSDV on the platform provide the same level of safety and environmental protection as the production riser BSDV. In addition, ensure that this complete assembly is fire-rated for 30 minutes. Attach the GLSDV by flanged connection directly to the API Spec. 6A component used to suspend and seal the gas-lift line contained within the production riser. To facilitate the repair or replacement of the GLSDV or production riser BSDV, you may install a manual isolation valve between the GLSDV and the API Spec. 6A component used to suspend and seal the gas-lift line contained within the production riser, or outboard of the production riser BSDV and inboard of the API Spec. 6A component used to suspend and seal the gas-lift line contained within the production riser.

9. On page 52280, the second table should read as follows:

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

10. On page 52281, the table should read as follows:

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

11. On page 52282, the first table should read as follows:

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

(iii) Tubing plug.	Not to exceed 6 months. Test by opening the well to possible flow. If a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 cubic feet per minute is observed, the plug must be removed, repaired, and reinstalled, or replaced. An additional tubing plug may be installed in lieu of removal.
(iv) Injection valves.	Not to exceed 6 months. Test by opening the well to possible flow. If a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 cubic feet per minute is observed, the valve must be removed, repaired and reinstalled, or replaced.

12. On page 52282, the second table should read as follows:

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

13. On page 52283, the first table should read as follows:

Item name	**Testing frequency and requirements**
(i) Pumps for firewater systems.	Must be inspected and operated according to API RP 14G, Section 7.2 (incorporated by reference as specified in § 250.198).
(ii) Fire- (flame, heat, or smoke) detection	Must be tested for operation and recalibrated every

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

14. On page 52283, the second table should read as follows:

Item name	**Testing frequency, allowable leakage rates, and other requirements**
(i) Surface-controlled SSSVs (including devices installed in shut-in and injection wells).	Tested semiannually, not to exceed 6 months. If the device does not operate properly, or if a liquid leakage rate > 400 cubic centimeters per minute or

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

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