UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE
GULF OF MEXICO OCS REGION

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NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL, GAS, AND SULPHUR LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO OCS REGION

Production Safety Systems Requirements

This Notice to Lessees and Operators (NTL) supersedes the Letter to Lessees (LTL) dated April 4, 1991, on this subject. It provides guidance on several issues with regard to production safety systems, updates regulatory citations, and includes a statement on the Paperwork Reduction Act of 1995.

1. **30 CFR 250.802(b). Exclusion of pressure safety high (PSH) and pressure safety low (PSL) sensors on downstream vessels in a production train**

As specified in American Petroleum Institute (API) Recommended Practice (RP) 14C, Section A.4, you must install a PSH sensor to provide over-pressure protection for a vessel. If an entire production train operates in the same pressure range, the PSH sensor protecting the initial vessel will detect the highest pressure in the production train, thereby providing primary over-pressure protection to each subsequent vessel in the production train. The intent of API RP 14C is not compromised under this scenario. Therefore, you may use API RP 14C Safety Analysis Checklist (SAC) reference A.4.a.3 to exclude all subsequent PSH sensors other than the PSH sensor protecting the initial vessel in a production train.

Furthermore, as specified in API RP 14C, Section A.4, you must install a PSL sensor to provide under-pressure protection for a vessel. If an entire production train operates in the same pressure range, the PSL sensor protecting the initial vessel will detect the lowest pressure in the production train, thereby providing primary under-pressure protection to each subsequent vessel in the production train. The intent of API RP 14C is not compromised under this scenario, since the PSL sensor protecting the initial vessel will detect leaks along the entire production train. Therefore, you may use API RP 14C SAC reference A.4.b.3 to exclude all subsequent PSL sensors other than the PSL sensor protecting the initial vessel in a production train, provided the pressure differential across the production train is not excessive (no more than 10 percent or 50 psi, whichever is greater).

For purposes of this section, a ***production train*** is a system of subsequent pressure vessels that (a) are not separated by specification breaks and possess the same maximum allowable working pressures (MAWP) and (b) are not separated by a pressure control valve (PCV), restrictions, or extensive piping that could cause a pressure drop across the system of more than 10 percent or 50 psi, whichever is greater.

2. **<u>30 CFR 250.802(b)</u>. Pressure safety valves (PSV) on flare and vent scrubbers**

As specified in API RP 14C, Section A.4, you must protect all pressure vessels with a PSV with sufficient capacity to discharge maximum vessel input rates. As defined in API RP 14C, any vessel operating above 5 pounds per square inch gauge (psig) is considered operating in pressure service. Flare and vent scrubber designs are typically based on a minimum of 5 psig backpressure; therefore, they are pressure vessels and not atmospheric vessels. Accordingly, you cannot use API RP 14C SAC reference A.5.b.2 for atmospheric vessels to exclude PSV's on flare and vent scrubbers.

Therefore, you must perform a process component analysis on all flare and vent scrubbers under API RP 14C, Section A.4, and protect each flare and vent scrubber with a PSV unless you can use API RP 14C SAC reference A.4.c.2 to exclude it. You may use a pressure safety element (PSE) in lieu of a PSV only on the above-mentioned components.

3. **<u>30 CFR 250.802(b)</u>. Vents and flame arrestors on atmospheric sumps**

As specified in API RP 14C, Section A.5, you must equip all atmospheric sumps with a minimum of one adequately sized vent system that includes a flame arrestor to prevent flame migration back to the vessel. You must analyze a sump with a ***manually*** controlled pressure source under API RP 14C, Section A.5. However, two independent vents or one vent and one PSV are required on an atmospheric sump that has an ***automatically*** controlled process inlet pressure source. Blanket gas is excluded; therefore, you can use API RP 14C SAC reference A.5.b.2, if applicable. Additionally, if the sump is a pressure vessel in atmospheric service, the use of API RP 14C SAC reference A.5.b.2 can be used to exclude the PSV or secondary vent.

Flame arrestors are not required on any atmospheric vessel vents located near the splash zone because of (a) potential plugging from corrosion and (b) the distance from other potential ignition sources. Document compliance with these requirements and obtain approval from the appropriate Gulf of Mexico OCS Region (GOMR) District Supervisor through new and revised Safety Analysis Function Evaluation (SAFE) charts and process flow diagrams.

4. **<u>30 CFR 250.802(b)</u>. Exclusion of the PSH sensor on small, low-volume pumps**

As specified in API RP 14C, Section A.7, you must provide all hydrocarbon pumps with a PSH sensor on the discharge line to shut off inflow and shut down the pump. However, API RP 14C SAC reference A.7.b.4 allows you to exclude the PSH sensor on small, low-volume pumps such as chemical injection-type pumps. This SAC reference 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 a flowline that is one inch or less in diameter, and terminates in a flowline or pipeline that is two inches or larger in diameter. If your pump does not meet these conditions, you must perform a process component analysis according to API RP 14C, Section A.7. In all cases, the PSV must be installed.

5. **30 CFR 250.802(b). Burner Safety Low (BSL) sensors on fired components**

As specified in APl RP 14C, Section C.2, the time for any safety device or system, including the fireloop, to effect a platform shutdown must not exceed 45 seconds after the automatic detection of an abnormal condition or the activation of an emergency shutdown (ESD) station. Therefore, the reaction time for the BSL sensor to activate the gas inlet shutdown valve must not exceed 45 seconds after the loss of a flame sufficient to immediately ignite combustibles entering the fire chamber.

6. **30 CFR 250.802(b). Flare and vent final discharge point**

As specified in API RP 14C, Section C.2, flare and vent systems for process components must discharge gas to locations where the gas will be diluted with air to below the lower explosive limit so it will not be a threat to the production facility or personnel. The final discharge point for atmospheric gas may be through a vertical, cantilevered, or underwater pipe. Accordingly, you should install all piping used for flaring or venting flammable gases in a manner that ensures a safe discharge away from the production facility or personnel. On all facilities, install booms upward, or underwater terminating at a safe distance from the facility. Piping installed downward and terminating either above or below the surface of the water beneath the platform is not acceptable. Indicate the locations of the vent on your process flow diagram.

7. **30 CFR 250.803(b)(1)(iii) and 30 CFR 250.1004(b)(3). Setting the PSH sensor on a process component or departing pipeline less than 5 percent below the setting of the PSV that is protecting the process component or departing pipeline**

The cited regulation (30 CFR 250.803(b)(1)(iii)) requires that the setting of a PSH sensor must be sufficiently below (5 percent or 5 psi, whichever is greater) the setting of the PSV on a process component to ensure that the pressure source is shut in before the PSV activates. On a case-by-case basis, GOMR District Supervisors have granted departures from this requirement by approving PSH sensor settings as close as 2 percent below the component PSV setting. This departure is conditioned upon the PSH sensor responding ***before*** the PSV. In considering a departure request, the appropriate GOMR District Supervisor determines whether it satisfies the intent of API RP 14C, giving special attention to the documented repeatability and response time of the PSH sensor.

A PSH sensor that derives its signal from a pressure transmitter has excellent repeatability and should respond prior to the PSV. A pneumatic PSH sensor, on the other hand, may not possess the required sensitivity or repeatability. The test sequencing of these safety devices will be the minimum difference between the set point of the PSH sensor and PSV; that is, during monthly PSH sensor testing, should the PSH sensor actuate at a pressure above the PSV set point minus the PSV tolerance (see API RP 14C, Section D.3.1), the PSH sensor would fail the test. You must then reset the PSH sensor accordingly.

Maintain a list of all devices that have been granted such a departure and the device test records at your nearest field location.

8. 30 CFR 250.803(b)(3). Automatic (demand) chokes on satellite wells

The cited regulation requires that all shutdown devices must function in a manual reset mode. The use of an automatic (demand) choke on a satellite well to return the well to production after its host platform has shut in does not comply with this regulatory requirement. A manual reset mode includes a remote manual reset function (through a SCADA system) you initiate at the host platform. Demand chokes are acceptable only when you use them in conjunction with the primary well shut-in device (SSV) and/or as only control devices, not shutdown devices.

9. 30 CFR 250.803(b)(4)(ii). Maximum closure time of shutdown valves (SDV's), underwater safety valves (USV's), and downhole valves on subsea wells

The cited regulation requires that the time to close a surface safety valve (SSV) must not exceed 45 seconds after the automatic detection of an abnormal condition or actuation of an ESD. It further requires that a surface-controlled subsurface safety valve (SCSSV) must close in two minutes or less after the shut-in signal has closed the SSV. It also makes provision for the District Supervisor to approve design-delayed closure times greater than 2 minutes if you can justify them based on an individual well=s mechanical/production characteristics.

Because of system limitations (i.e., direct hydraulic, distance from host facility), the time to close USV's and SCSSV's on subsea wells during a surface ESD condition may, in many cases, exceed the times allowed by the subject regulation (45 seconds for USV's and 2 minutes 45 seconds for SCSSV's).

Therefore, if the safety system of your subsea well requires time beyond that specified in the subject regulation to close a USV or SCSSV, you may request that the appropriate GOMR District Supervisor grant you a departure under 30 CFR 250.142. In making a decision on your request, the GOMR will consider historical information from similar subsea developments, the following stipulations, and the following valve closure time guidelines.

Stipulations:

a. The MAOP of the pipeline system is greater than the maximum shut-in tubing pressure (SITP) of the well(s).
b. The integrity of the pipeline is automatically monitored by a PSH sensor and a PSL sensor (the PSH sensor is set at least 5 percent above the well(s) maximum SITP, and the PSL sensor is set at least 15 percent below the lowest operating range of the pipeline) installed upstream of the SDV. Should either the PSH or PSL sensor actuate, the initiation of USV closure begins without delay.
c. The boarding pipeline SDV is located in a horizontal section within 10 feet of the boarding pipeline riser.
d. The pipeline SDV is tested according to the requirements of 30 CFR 250.804(a)(4); that is, view the SDV as if it were a non-certified SSV.
e. Any loss of communication during an ESD event between the subsea wellhead and the host platform immediately initiates closing of the USV and the SCSSV.
f. Any ESD action on the host facility immediately closes the USV, SCSSV, and pipeline SDV.

Valve Closure Time Guidelines:

SENSED ACTIVATION	PIPELINE SDV	USV	SCSSV
Process Upsets	Within 45 seconds	Within 20 minutes after upset	Within 40 minutes after USV closure
Pipeline PSL	Within 45 seconds	Activation concurrent with SDV closure	Activation concurrent with SDV closure
ESD or Fireloop	Within 45 seconds	Activation concurrent with SDV closure*	Activation concurrent with SDV closure*

*The appropriate GOMR District Supervisor may grant a departure for you to delay the time to close a USV and SCSSV for a subsea well after activation of a platform ESD or Fireloop for up to 20 minutes, if you agree in writing to:

a. Install a temperature safety high (TSH) sensor, connected to the pipeline PSL sensor circuit, within 5 feet of the boarding pipeline SDV that will immediately initiate a shut-in action of the USV;
b. Ensure that your SDV is fire rated by API Spec 6A to 30 minutes; and
c. Issue a manual acknowledgment command to the program logic controller (PLC) that verifies a non-emergency status at least once every 5 minutes during this 20-minute time period to keep the reset timer active.

10. <u>30 CFR 250.803(c)(1)</u>. Time delay circuitry applied to PSL sensors

The cited regulation prohibits you from bypassing or blocking out any required surface safety device unless you have placed it temporarily out of service for startup, maintenance, or testing operations. In adopting API 14C, 30 CFR 250.802(b) requires that you provide process components with a PSL sensor to shut off inflow to the component when leaks large enough to reduce pressure occur. The GOMR recognizes that time delay circuitry that bypasses activation of PSL shutdown logic for a specified time period is needed (and is currently being used extensively in the Gulf of Mexico) on all process and product transport equipment during startup and idle operations. If this logic is not installed, you must manually bypass (pin out or disengage) the PSL sensor. This manual bypass operation is subject to human error and usually exceeds the 45-second time period granted by the automatic logic of Class B, Class C, and Class B/C circuitry.

For purposes of this paragraph, these safety devices are defined as follows:

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

b. Class C devices are safety devices in which the logic allows for PSL sensors to be bypassed until the component comes into full service.

c. Class B/C devices are safety devices in which the logic allows for the PSL sensors to incorporate a combination of Class B and Class C circuitry. These devices are used to ensure that 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 (a) the Class B timer expires after 45 seconds from start activation or (b) the Class C bypass is initiated until the pump builds up pressure above the PSL set point and the PSL sensor comes into full service. When the PSL sensor comes into full service, the PSL sensor is fully active. If the PSL sensor should trip while the pump is running, the pump will shut down and the Class B/C bypass circuit will remain inactive until the safety system devices are cleared and reset.

Industry standard Class B, Class C, and Class B/C logic may be applied to all PSL sensors installed on process equipment without a specific departure being required. **The time delay must not exceed 45 seconds**. Any time delay greater than 45 seconds requires a specific departure.

For purposes of this section, the term **comes into full service** means the time at which the start up pressure equals or exceeds the set pressure of the PSL sensor, the system reaches a stabilized Anormal" pressure, and the PSL sensor clears.

11. <u>30 CFR 250.804</u>. Testing of safety devices associated with subsea wells

The most critical valve in a subsea safety system for protection of human life and the environment is the boarding pipeline SDV. Although the USV at the well is important, redundant valves subsea, as well as the remote location of the subsea system, minimize the risk involved to human life, the environment, and the structure involved. Consequently, the appropriate GOMR District Supervisor may approve a test schedule that avoids the unnecessary stroking of subsea valves, thereby extending the life of the valves. However, the GOMR may grant this alternate test procedure under 30 CFR 250.141 only if you test the boarding pipeline SDV monthly and immediately repair or replace any pipeline SDV you find that is not operating properly or is leaking.

The table below summarizes the testing requirements for safety system devices associated with subsea wells.

VALVE NAME	TEST PERIOD	TEST CRITERIA
SCSSV (250.804(a)(1)(i))	Semi-annually not to exceed 6 calendar months	Acceptable leakage rate < 400 cubic centimeters per minute liquid or <15 cubic feet per minute gas
USV (250.804(a)(4))	Quarterly not to exceed 120 days	Acceptable leakage rate < 400 cubic centimeters per minute liquid or <15 cubic feet per minute gas
SDV (250.1004(b)(2))	Monthly not to exceed 6 weeks	Leakage rate zero

12. <u>30 CFR 250.804(a)(10)</u>. Testing frequency for computer-driven ESD systems

Electronic-based ESD systems that use PLC's to monitor the ESD system are more reliable than pneumatic ESD systems. Therefore, the integrity of the ESD system is not compromised with an extended test frequency. When you have an ESD system that uses a PLC or is electronic-based, the appropriate GOMR District Supervisor may grant a departure under 30 CFR 250.142 from the requirement to test such an ESD system monthly to allow for quarterly testing. The GOMR may grant this departure only if the entire system from the ESD station to the control panel ESD relay is electronic-based or entirely controlled by the PLC.

For ESD systems that use PLC's, actuation test the electronic, electronic/pneumatic circuitry monthly, and

a. For ***subsea systems***, effect a complete system shut in quarterly, not to exceed 120 days. This action may coincide with your SDV or USV test.
b. For ***non-subsea systems,*** test the ESD according to the requirements of 30 CFR 250.804(a)(10).

Paperwork Reduction Act of 1995 Statement

The information collection referred to in this NTL provides clarification, description, or interpretation of requirements contained in 30 CFR 250, Subparts A, H, and J. The Office of Management and Budget (OMB) approved the information collection requirements for these regulations and assigned OMB Control Nos. 1010-0114, 1010-0059, and 1010-0050, respectively. This NTL does not impose additional information collection requirements subject to the Paperwork Reduction Act of 1995.

Contacts

Please direct any questions you may have regarding this NTL to the Production Engineer in the respective GOMR District Office.

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