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

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

NTL No. 2009-G36

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Using Alternate Compliance in Safety Systems for Subsea Production Operations

This Notice to Lessees and Operators (NTL) replaces items Nos. 9, 10, 11, and 12 of NTL No. 2000-G13, Production Safety System Requirements, issued May 25, 2000. The remaining items of NTL No. 2000-G13 were either replaced by the items in or abolished by NTL No. 2009-G18, effective September 9, 2009.

Purpose

The purpose of this NTL is to authorize the use of the Barrier Concept as the basis for using alternate procedures or equipment in the safety systems for subsea production operations and to clarify the differences between topsides and subsea production operation.

Authority

The Minerals Management Service (MMS) regulations contained in 30 CFR 250, Subpart H, Oil and Gas Production Safety Systems, at 30 CFR 250.802, 30 CFR 250.803, and 30 CFR 250.804 prescribe requirements for designing, installing, and operating surface production-safety systems, additional production system requirements, and requirements for production safety-system testing and recording protocol, respectively. In addition, MMS has incorporated API RP 14C, Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms (see 30 CFR 250.198) into its regulations.

In accordance with 30 CFR 250.292(o), you must include a list of any alternate compliance procedures for which you anticipate requesting approval in your deepwater operations plan (DWOP).

Pursuant to 30 CFR 250.141, the MMS Gulf of Mexico OCS Region (GOMR) District Manager or Regional Supervisor may approve a site-specific alternate procedure or equipment as long as it provides a level of safety and environmental protection that equals or surpasses current MMS regulatory requirements.

Background

Over the past several years, the MMS GOMR and industry have gained experience with subsea wells and equipment as production facilities are being constructed in deep and ultra-deep water depths. The MMS GOMR conducted a risk analysis to study the differences between traditional dry tree wells (which are the basis for the MMS regulations at 30 CFR 250, Subpart H cited above) and subsea wells, pipelines, and other subsea equipment (the nature of which poses difficulties for testing and replacing underwater safety devices) and to determine if an alternate system configuration could provide an equivalent or better level of safety with increased reliability without placing undue burden on you. As a result of this analysis, the MMS GOMR developed the Barrier Concept, which has become the basis for approving the use of procedures or equipment for subsea production operations different from those prescribed in 30 CFR 250, Subpart H.

The Barrier Concept

The Barrier Concept involves the use of a boarding shut-down valve (BSDV), which assumes the role of the surface safety valve (SSV) required by 30 CFR 250, Subpart H for a traditional dry tree. This ensures the maximum level of safety for the production facility and the people aboard the facility. Because the BSDV becomes the most critical component of the subsea system, it is necessary that this valve be subject to rigorous design and testing criteria.

Therefore, to use the Barrier Concept in the design of your subsea production safety system:

1. Ensure that the internal design pressure of the pipeline(s), riser(s), and BSDV(s) is fully rated for the maximum source pressure (MSP) and comply with the design requirements set forth in 30 CFR 250, Subpart J unless the MMS GOMR approves an alternate design.

2. Use a BSDV that meets the requirements of API Spec 6A and API Spec 6AV1, is fire rated for 30 minutes, and is pressure rated for the maximum allowable operating pressure (MAOP) approved in your pipeline application.

3. 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).

4. Install a temperature safety element (TSE) and locate it within 5 feet of each BSDV. Do not use a resettable timer on the TSE associated with a BSDV.

5. Test the BSDV for leakage monthly, not to exceed 6 weeks. If the monthly leak rate test does not confirm zero leakage of the BSDV, shut in all sources to the BSDV and repair or replace it before resuming production.

Additional Operating Conditions Not Part of the Barrier Concept

1. If a necessary alteration or disconnection of the pipeline or umbilical of any subsea well affects your ability to monitor casing pressure or test any of the subsea valves or equipment covered by this NTL, contact the appropriate MMS GOMR District Office at least 48 hours in advance and submit a repair or replacement plan to conduct the required monitoring and testing.

2. When operating a mobile offshore drilling unit (MODU) or other type of workover vessel in an area with producing subsea wells, either

A. Suspend production from all such wells that could be affected by a dropped object, including upstream wells that flow through the same pipeline, or

B. Establish direct, real-time communications between the MODU and the production facility control room and prepare a plan to shut in any wells that could be affected by a dropped object. If an object is dropped, the driller should immediately secure the well directly under the MODU using the ESD on the well control panel located on the rig floor while simultaneously communicating with the platform to shut in all affected wells. Maintain without disruption and continuously verify communication between the platform and the MODU. Should communications be lost between the MODU and the platform for 20 minutes or more, make sure that the platform initiates a shut in of all wells that could be affected by a dropped object.

In either case, contact the appropriate MMS GOMR District Office before you resume production if any object was dropped that could affect a well(s) near the MODU.

3. After you install the subsea tree but before the rig or installation vessel leaves the area, test all valves and sensors to ensure that they are operating as designed and meet all the conditions specified in this NTL. If you cannot perform these tests, notify the appropriate MMS GOMR District Office.

4. Be advised that if you wish to make any material changes to your DWOP after it has been approved, you must submit a revision to the MMS GOMR for approval. Approval of an alternate compliance request not covered by this NTL is not guaranteed, and you should submit it and receive approval before you devote substantial resources to its implementation.

Alternate Compliance

The MMS GOMR has determined that use of the Barrier Concept in the design of your subsea production safety system provides a level of safety and environmental protection that equals or surpasses current MMS requirements. Accordingly, the MMS GOMR hereby approves the following alternate compliance procedures and equipment provided you adhere to the general conditions for use of the Barrier Concept and the Additional Operating Conditions specified above and the conditions specified below with each item. For these items, you do not need to include them in the list of alternate compliance requests in your DWOP nor do you need to make a specific request for approval of alternate compliance in accordance with 30 CFR 250.141.

1. **30 CFR 250.517(d) and 30 CFR 250.617(d), Tubing and wellhead equipment.**

May I place the Master Valve and the Underwater Safety Valve (USV) in the horizontal run of the Christmas Tree (tree)?

Yes. You may install a horizontal subsea tree which has the USV, the production master valve (PMV), and the production wing valve (PWV) in the horizontal run of the tree provided the tree contains two mechanical pressure barriers between the production fluid and the environment within any opening in the tree or flow path.

2. **30 CFR 250.802(b), Design, installation, and operation of surface production-safety systems – Platforms.**

Can a single flow safety valve (FSV) located on the platform be used to protect multiple subsea flowlines, pipelines, and/or wells??

Yes. You may install a single FSV on the platform to protect multiple subsea pipelines or wells that tie into a single pipeline riser provided that you install an FSV for each riser and test it in accordance with the criteria prescribed in 30 CFR 250.804(a)(6).

3. **30 CFR 250.802(b), Design, installation, and operation of surface production-safety systems – Platforms.**

Can a single pressure safety high low (PSHL) sensor located on the platform be used to protect multiple subsea flowlines, pipelines, and/or wells?

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

4. **30 CFR 250.804(a)(1)(i) and 30 CFR 804(a)(5), Production safety-system testing and records - Inspection and testing.**

May I test the surface-controlled subsurface safety valve (SCSSV) and USV in suspended wells at intervals greater than 6 months?

Yes. You may test the SCSSV and USV in suspended wells at intervals greater than 6 months provided that you protect each shut-in well with three pressure barriers (i.e., a closed and tested SCSSV and two closed and tested tree valves). For the purpose of this NTL, a suspended well is defined as a subsea well that cannot be controlled or monitored from the host facility for 30 days or more. Test the SCSSV for leakage in accordance with 30 CFR 250.801(e)(4) and confirm zero leakage of all three barriers.

Install and maintain a sealing pressure cap on the pipeline connection hub until the pipeline is installed and connected. Design the pressure cap to accommodate monitoring for pressure between

the production wing valve and the cap. Incorporate a diagnostics capability into the design such that a remotely operated vehicle (ROV) can bleed pressure off and monitor for build-up. ***Confirm*** barrier integrity in each well at intervals not to exceed 12 months from the time of initial testing.

Make sure that a drilling vessel capable of intervention into the suspended well is readily accessible for use until you bring the wells on line.

The shut-in period for each suspended well cannot exceed 24 months. Submit a request to the appropriate MMS GOMR District Office if you need to extend this time period.

5. 30 CFR 250.803(c)(1), Additional production system requirements - General platform operations.

May there be a time delay on the circuitry for the pressure safety low (PSL) sensors?

Yes. You may apply industry standard Class B, Class C, and Class B/C logic to all PSL sensors installed on process equipment without approval of a specific alternate compliance request. If you do, make sure that the time delay does not exceed 45 seconds. Any time delay greater than 45 seconds requires approval of a specific alternate compliance request. Make a note on your field test records when a specific alternate compliance is applied. For purposes of this paragraph, the PSL sensors are defined as follows:

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

B. 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).

C. 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 after 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. 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.

A time delay circuitry that bypasses activation of PSL sensor shutdown logic for a specified time period may be needed 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. The time delay must not exceed 45 seconds. Any time delay greater than 45 seconds requires approval of a specific alternate compliance request from the appropriate MMS GOMR District Office.

6. 30 CFR 250.802(d), Design, installation, and operation of surface production-safety systems - Use of SSV's and USV's.

May I re-designate another USV as the primary USV (USV1) should the original USV1 fail to operate properly?

Yes. You may equip your tree with two or more valves qualified to be designated as a USV. If you do, designate one valve as the USV1 and test it in accordance with the guidelines provided in this NTL. If the USV1 fails to operate properly or exhibits a leakage rate greater than that specified in this NTL, notify the appropriate MMS GOMR District Office and designate another qualified valve per API Spec 6A and API Spec 6AV1 as the primary valve (USV1). Test the newly designated USV1 in accordance with guidelines provided in this NTL. This valve must be located upstream of the choke to be designated as a USV.

7. 30 CFR 250.801(f)(2), Subsurface safety devices – Subsurface safety devices in shut-in wells.

May the hydraulic control to an SCSSV that is controlled via an electro-hydraulic control umbilical be considered inoperative if the hydraulic control pressure to the individual well cannot be isolated?

Yes. Due to the complexity of the subsea hydraulic distribution of electro-hydraulic (EH) controlled subsea fields, simply isolating the hydraulic control pressure to one subsea well may not be feasible. The MMS GOMR considers the hydraulic control to an SCSSV of an EH-controlled subsea well as rendered inoperable if you perform all of the following. The appropriate MMS District Office may consider alternate methods on a case-by-case basis:

A. Disable the control function of the SCSSV within the logic of the programmable logic controller (PLC) which controls the subsea well.

B. Place a pressure alarm high (PAH) on the control line to the SCSSV of the subsea well.

C. Close the USV and at least one other tree valve on the subsea well.

8. 30 CFR 250.803(b)(4)(ii), Additional production system requirements - ESD

May alternative valve closure times be considered for ESD and sensor activation?

Yes. The subject regulation governs valve closure timing. You may operate your production system under alternate compliance using the valve closure times listed in the tables in Appendix A

(Valve Closure Timing, Electro-Hydraulic Control System), Appendix B (Valve Closure Timing, Electro-Hydraulic Control System with Loss of Communication), and Appendix C (Valve Closure Timing, Direct-Hydraulic Control System) of this NTL provided you adhere to all of the general conditions for use of the Barrier Concept and the Additional Operating Conditions specified above, and comply with all of the following:

A. Adhere to each and every specified valve closure timing limitation specified in the tables in Appendices A, B, and C and the valve closure testing frequency specified in the table in Appendix D (Valve Closure Testing) unless the appropriate MMS GOMR District Manager or the Technical Assessment and Operations Support (TAOS) Section Chief grants approval otherwise.

B. After installation, verify, by test, the valve closure timing for all electro-hydraulic and direct-hydraulic systems. Do not initiate production if your valve closure times do not adhere to those specified in the tables in Appendices A, B, and C or in an existing approved alternate compliance request.

C. Install a PSHL sensor upstream of the BSDV.

D. In order for a valve to be designated as a USV, install it upstream of the choke valve.

E. If you install an alternate isolation valve (AIV) to complement the USV1, make sure that it meets the requirements of API Spec 6A.

F. If you have an electro-hydraulic system and experience a loss of communications (EH Loss of Comms)

i. Notify the appropriate MMS District Office within 12 hours of detecting the loss of communication if you can meet the EH Loss of Comms valve closure timing conditions specified in the table in Appendix B of this NTL.

ii. Notify the appropriate MMS District Office immediately after detecting the loss of communication if you cannot meet the EH Loss of Comms valve closure timing conditions specified in the table in Appendix B. Shut in production by initiating a bleed of the low pressure (LP) hydraulic system or the high pressure (HP) hydraulic system within 120 minutes after loss of communication. Bleed the other hydraulic system within 180 minutes after loss of communication.

iii. Obtain prior approval from the appropriate MMS District Manager if you want to continue to produce after loss of communication when you cannot meet the EH Loss of Comms valve closure times specified in the table in Appendix B. In your request, include an alternate valve closure table that your system is able to achieve. The appropriate MMS District Manager may also approve an alternate hydraulic bleed schedule to allow for hydrate mitigation and orderly shut in.

The ESD, TSE, PSHL sensor activation and process upset conditions that will initiate a USV and SCSSV valve closures are defined below:

A. Process Upset - When an upset in the production process train occurs downstream of the BSDV.

B. Pipeline PSHL Sensor - When either a high or low pipeline pressure condition is detected by a PSHL sensor located upstream of the BSDV.

C. Platform Emergency Shutdown (ESD) or Platform Temperature Safety Element (TSE) - An ESD or TSE on the host platform not associated with the BDSV. (See item D below for the conditions for the TSE associated with the BSDV.)

D. Subsea ESD (activated from the host platform) or a TSE at the BSDV - An ESD initiated by the host platform because of a problem subsea, or a TSE associated with the BSDV.

E. Subsea ESD (initiated from a MODU) - An ESD initiated by a MODU because of a dropped object from a rig or intervention vessel.

9. 30 CFR 250.804(a)(1)(i) and 30 CFR 250.804(a)(5), Production safety-system testing and records – Inspection and testing.

May an alternate valve testing schedule be approved?

Yes. The subject regulation governs SCSSV and USV closure testing. You may operate your production system under alternate compliance using the valve closure testing schedules listed in the table in Appendix D of this NTL provided you adhere to all of the general conditions for use of the Barrier Concept and the Additional Operating Conditions specified above. You must adhere to each and every specified valve closure testing frequency in the table in Appendix D unless the appropriate MMS GOMR District Manager or the Technical Assessment and Operations Support (TAOS) Section Chief grants approval otherwise.

Exclusions

1. If you have received approval from the MMS GOMR for any alternate compliance request, regarding mitigations, valve closure timing, or valve closure testing, you may continue to operate as currently approved.

2. If you plan to tie back new wells to an existing platform, you may request, in your DWOP, to use the alternate compliance mitigations, valve closure timing, and valve closure testing schedule previously approved for that platform. To make this request, include in your DWOP:

A. Alternate compliance(s) requested; and
B. A copy of the MMS GOMR letter that previously approving the alternate compliance(s).

3. If you have previously received approval from the MMS GOMR for any alternate compliance, and you wish to modify your system to conform to conditions in this NTL, you may request a change to your departure list, valve closure timing, and valve closure testing by

submitting a supplemental DWOP to the MMS GOMR TAOS Section. If you request to modify your alternate compliances, you must accept all the conditions of this NTL. You will not be able to combine your previously approved alternate compliances with alternate compliances allowed by this NTL.

Guidance Document Statement

The MMS issues NTL's as guidance documents in accordance with 30 CFR 250.103 to clarify, supplement, and provide more detail about certain MMS regulatory requirements and to outline the information you provide in your various submittals. Under that authority, this NTL sets forth a policy on and an interpretation of a regulatory requirement that provides a clear and consistent approach to complying with that requirement. However, if you wish to use an alternate approach for compliance, you may do so, after you receive approval from the appropriate MMS office under 30 CFR 250.141.

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 H and J. The Office of Management and Budget (OMB) approved the information collection requirements for this regulation and assigned OMB Control Numbers 1010-0059 and 1010-0050, respectively. This NTL does not impose any additional information collection requirements subject to the Paperwork Reduction Act of 1995.

Contacts

Please direct any questions you may have regarding this NTL to Christy Lan, Technical Assessment and Operations Support Section, by telephone at (281) 987-6841 or by e-mail at christy.lan@mms.gov.

[original signed]

Lars T. Herbst
Regional Director

Appendices (4)

*Appendix A: Valve Closure Timing, Electro-Hydraulic Control System**

Conditions[10]	**Pipeline BSDV**	**USV1**[1]	**USV2**[1]	**Alternate Isolation Valve**[2]	**SCSSV**	**LP**[14] **Hydraulic System**	**HP**[14] **Hydraulic System**
Process upset	Close within 45 seconds after sensor activation.[3]	No automatic closure.			No automatic closure.	No bleed.	No bleed.
Pipeline PSHL[8,4]	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.			60-minute resettable timer; close within 24 hours after sensor activation.	No bleed.	Initiate unrestricted bleed within 24 hours after sensor activation.
ESD/TSE[9] (Platform)	Close within 45 seconds after ESD or sensor activation.	5-minute resettable timer; close within 20 minutes after ESD or sensor activation.[6]	Close within 20 minutes after ESD or sensor activation.		20-minute resettable timer; close within 60 minutes after ESD or sensor activation.[5]	60-minute resettable timer; initiate unrestricted bleed within 24 hours after ESD or sensor activation.[13]	60-minute resettable timer; initiate unrestricted bleed within 24 hours after ESD or sensor activation.[13]
Subsea ESD (Platform)[11] or BSDV TSE[12]	Close within 45 seconds after ESD or sensor activation.	Close one or more valves within 2 minutes and 45 seconds after ESD or sensor activation. Close all tree valves within 10 minutes after ESD or sensor activation.			Close within 10 minutes after ESD or sensor activation	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation.	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation.
Subsea ESD[7] (MODU)	No automatic closure.	Initiate valve closures immediately. You may allow for closure of the tree valves immediately prior to closure of the SCSSV if desired.				Initiate unrestricted bleed immediately.	Initiate unrestricted bleed within 10 minutes after ESD activation.

* This table provides the maximum allowable closure times.

[1] In order to designate a valve as the USV, locate it upstream of the choke valve. A USV2 is not a regulatory requirement, but the master or wing valve is often qualified per API Spec 6AV1 as a USV by the lessee or operator for operational flexibility.

[2] When applicable, ensure that the alternate isolation valve (AIV) is an API Spec 6A valve to be recognized as an AIV per the table above. An AIV is not a regulatory requirement, but you may choose to install one for operational flexibility.

[3] You may reopen the BSDV to blow down the pipeline to prevent hydrates provided you have secured the well(s) and ensured adequate protection.

[4] Locate the PSHL sensor upstream of the BSDV. The timer may be reset as many times as necessary with operator acknowledgement up to 24 hours provided that the integrity of the subsea system is verified.

[5] Make sure that the SCSSV closes within 20 minutes after ESD activation unless you activate the timer. Close the SCSSV within 60 minutes after ESD or sensor activation

[6] The designated USV1 closes within 5 minutes after ESD activation unless you activate the timer. Close the USV within 20 minutes after ESD or sensor activation.

[7] Pertains to dropped objects from rig or intervention vessel. Close all wells in the proximity of the MODU according to this table in the event of a dropped object. Notify the appropriate MMS GOMR District Manager before resuming production.

[8] Close all wells and pipelines associated with a dual or multi pipeline system according to the PSHL sensor closure schedule. Obtain approval from the appropriate MMS GOMR District Manager to resume production in the unaffected pipeline(s) of a dual or multi pipeline system. Should it be determined that the PSHL sensor activation was a false alarm, you may return the wells to production without contacting the appropriate MMS GOMR District Manager.

[9] This closure table applies to an ESD or TSE not associated with the BSDV at the host facility. You may use a 5-minute manual resettable timer on the program logic controller for the USV and a 20-minute manual resettable timer on the program logic controller for the SCSSV. The TSE associated with the BSDV may not use a resettable timer and has different valve closure time restrictions.

[10] Design the subsea control system to meet the valve closure times listed in this table. Upon installation, verify the valve closure times.

[11] The host facility initiates an ESD because of a problem subsea. An example would be when the platform shuts in subsea wells beneath a MODU due to loss of communication between the MODU and the platform for more than 20 minutes or for a hurricane evacuation.

[12] Do not allow resettable timers to delay valve closure when the BSDV TSE is activated or allow the BSDV TSE to be placed in bypass mode. Locate a TSE within 5 feet of the BSDV. Make sure that the BSDV is fire rated for 30 minutes as per API Spec 6A.

[13] Perform an unrestricted bleed of the LP and HP hydraulic systems within 60 minutes after ESD activation unless you activate the timer. After 24 hours, perform an unrestricted bleed of the LP and HP hydraulic systems. This does not apply if communication to the well is lost.

[14] Bleeding the LP and HP hydraulic system pressures ensures that the valves are locked out of service following an ESD or fire and cannot inadvertently be reopened.

*Appendix B: Valve Closure Timing, Electro-Hydraulic Control System with Loss of Communication**

Conditions[8]	**Pipeline BSDV**	**USV1**[1]	**USV2**[1]	**Alternate Isolation Valve**[2]	**SCSSV**	**LP Hydraulic System**	**HP Hydraulic System**
Process Upset	Close within 45 seconds after sensor activation.[3]	No automatic closure.			No automatic closure.	No bleed.	No bleed.
Pipeline PSHL[4, 6]	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.
ESD/TSE (Platform)[7]	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.
Subsea ESD (Platform)[9] or BSDV TSE[10]	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 SCSSV closure within 20 minutes.
Subsea ESD (MODU)[5]	No automatic closure.	Initiate closure immediately. You may allow for closure of the tree valves immediately prior to closure of the SCSSV if desired.				Initiate unrestricted bleed immediately.	Initiate unrestricted bleed immediately.

* This table provides maximum allowable closure times.

[1] In order to designate a valve as the USV, locate it upstream of the choke valve.

[2] When applicable, ensure that the alternate isolation valve (AIV) is an API Spec 6A valve to be recognized as an AIV per the table above.

[3] You may reopen the BSDV to blow down the pipeline to prevent hydrates provided you have secured the well and ensured adequate protection.

[4] Locate the PSHL sensor upstream of the BSDV.

[5] Pertains to dropped objects from rig or intervention vessel. Close all wells in the proximity of the MODU according to this table in the event of a dropped object. Notify the appropriate MMS GOMR District Manager before resuming production.

[6] Close all wells and pipelines associated with a dual or multi pipeline system according to the PSHL closure schedule. Obtain approval from the appropriate MMS GOMR District Manager to resume production in the unaffected pipeline(s) of a dual or multi pipeline system. Should it be determined that the PSHL activation was a false alarm, you may return the wells to production without contacting the appropriate MMS GOMR District Manager.

[7] This closure table applies to an ESD or TSE not associated with the BSDV at the host facility. The TSE associated with the BSDV has different valve closure time restrictions.

[8] Design the subsea control system to meet the valve closure times listed in this table. Upon installation, the appropriate MMS GOMR District Manager may ask you to verify the closure time of the USV(s), which may include visual authentication by diver or ROV.

[9] The host facility initiates an ESD because of a problem subsea. An example would be when the platform shuts in subsea wells beneath a MODU due to loss of communication between the MODU and the platform that lasts longer than 20 minutes.

[10] Locate a TSE within 5 feet of the BSDV. Make sure that the BSDV is fire rated for 30 minutes as per API Spec 6A.

*Appendix C: Valve Closure Timing, Direct-Hydraulic Control System**

Conditions[9]	**Pipeline BSDV**	**USV1**[1]	**USV2**[1]	**Alternate Isolation Valve**[2]	**SCSSV**	**LP Hydraulic System**	**HP Hydraulic System**
Process Upset	Close within 45 seconds after sensor activation.[3]	No automatic closure.			No automatic closure.	No bleed.	No bleed.
Flowline PSHL[4,6]	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.
ESD/TSE (Platform)[7]	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.
Subsea ESD (Platform)[10] or BSDV TSE[8]	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.
Subsea ESD[5] (MODU)	No automatic closure.	Initiate closure immediately. If desired, you may allow for closure of the tree valves immediately prior to closure of the SCSSV.				Initiate unrestricted bleed immediately.	Initiate unrestricted bleed immediately.

* This table provides maximum allowable closure times.

[1] In order to designate a valve as the USV1, locate it upstream of the choke valve. A USV2 is not a regulatory requirement, but the master or wing valve is often qualified per API Spec 6AV1 as a USV by the lessee or operator for operational flexibility.

[2] When applicable, ensure that the alternate isolation valve (AIV) is an API Spec 6A valve to be recognized as an AIV per the table above. An AIV is not a regulatory requirement, but you may choose to install one for operational flexibility.

[3] You may reopen the BSDV to blow down the pipeline to prevent hydrates provided you have secured the well(s) and ensured adequate protection.

[4] Locate the PSHL sensor upstream of the BSDV.

[5] Pertains to dropped objects from rig or intervention vessel. Close all wells in the proximity of the MODU according to this table in the event of a dropped object. Notify the appropriate MMS GOMR District Manager before resuming production.

[6] Close all wells and pipelines associated with a dual or multi pipeline system according to the PSHL sensor closure schedule. Obtain approval from the appropriate MMS GOMR District Manager to resume production in the unaffected pipeline(s) of a dual or multi pipeline system. Should it be determined that the PSHL sensor activation was a false alarm, you may return the wells to production without contacting the appropriate MMS GOMR District Manager.

[7] This closure table applies to an ESD or TSE not associated with the BSDV at the host facility. The TSE associated with the BSDV has different valve closure timing requirements

[8] Locate a TSE within 5 feet of the BSDV but do not place the TSE in bypass mode. Make sure that the BSDV is fire rated for 30 minutes as per API Spec 6A.

[9] Design the subsea control system to meet the valve closure times listed in this table. Upon installation, the appropriate MMS GOMR District Manager may ask you to verify the closure time of the USV(s), which may include visual authentication by diver or ROV.

[10] The host facility initiates an ESD because of a problem subsea. An example would be when the platform shuts in subsea wells beneath a MODU due to loss of communication between the MODU and the platform that lasts more than 20 minutes.

Appendix D: Valve Closure Testing[2]

Valve	Allowable Leakage Rate	Testing Frequency
Pipeline BSDV	Zero Leakage	Monthly, not to exceed 6 weeks
Electronic ESD Logic	N/A	Monthly, not to exceed 6 weeks
Electronic ESD Function[3]	N/A	Quarterly, not to exceed 120 days
USV1	400 cc per minute of liquid or 15 scf per minute of gas	Quarterly, not to exceed 120 days
SCSSV	400 cc per minute of liquid or 15 scf per minute of gas	Semiannually, not to exceed 6 calendar months
USV2	N/A[1]	N/A[1]

[1] Should the designated primary USV fail to test or meet the allowable leakage rate as outlined above, notify the appropriate MMS GOMR District Office and designate another certified subsea valve as the primary USV. Once designated, test the valve for conformance with the conditions specified in this NTL.

[2] Notify and receive approval from the appropriate MMS GOMR District Office before you perform any subsea intervention that modifies the existing subsea infrastructure in a way that may affect the testing frequencies listed in the table above.

[3] 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.