OOC SUBPART H FORUM OUTPUT DOCUMENT

Issue Date May 12, 2017

Disclaimer

"The materials generated for the 2017 OOC Subpart H Forum, inclusive of the checklist files, were generated from a volunteer effort within the OOC SEMS Subcommittee. These materials drew upon lessons learned from multiple operators and contractors from a wide variety of activities. Each operator or entity is solely responsible for verification and modification of these materials for their organization's needs prior to use. The OOC, its staff and all of the contributing volunteers assume no liability for the content or use of the produced materials."

OFFSHORE OPERATORS COMMITTEE
staff@theooc.us

1 Forum Objectives and Planning Committee

The main objectives of the forum were:

1) For operators to share challenges and lessons learned in implementing the requirements of the BSEE's Subpart H – Production Safety Rule; and

2) For BSEE representatives to conduct a Q&A session with industry to clarify the requirements of Subpart H.

1.1 Planning Committee

This table contains the names and companies of those involved in the planning and organizing of this forum.

Name	Company
David Dykes	Chevron
David Helminiak	EnVen Energy Ventures
David Broussard	Fieldwood Energy
Joel Plauche	Fieldwood Energy
Bill Terrebonne	Shell
Dave Lemonier	Shell
Steve Frantz	Talos Energy

2 Agenda

The 2017 OOC Subpart H forum took place at the Sheraton Galleria, Metairie, LA on March 28th, 2017. The forum agenda is below.

8:30-9:00	***Registration / Breakfast***
9:00-9:15	***Welcome / Introduction / Anti-Trust / Agenda Review***
9:15-10:15	***Operator Panel – Current Compliance Challenges & Strategies*** Panel of operators will discuss key challenges with the new requirements and share strategies for achieving compliance. Q&A will follow.
10:15-10:30	***BREAK***
10:30-11:30	***Operator Panel - PSV, Flame Arrestors & Other Issues*** Industry panel will discuss challenges with the lifting the main valve for pilot operated PSVs, inspecting flame arrestors, and other issues. Q&A will follow.
11:30-12:30	***LUNCH – Networking***
12:30-1:45	***Q&A Session with BSEE*** BSEE representatives will address questions submitted by industry prior to the forum and take questions from the room.

1:45-2:00	***BREAK***
2:00-3:00	***Continuation of BSEE Q&A***
3:00-3:30	***Industry Small Group Working Session – Top 5 Challenges*** Forum attendees will divide into small groups to identify the Top 5 challenges with the new requirements, and be asked for ideas on how to address each issue.
3:30-4:00	***Share Results of Small Groups*** Results from each small group will be shared with the larger room. Attendees will be asked to vote on the Top 5 issues for industry.
4:00-4:30	***Path Forward & Closing*** OOC will summarize the results of the day and discuss the path forward for addressing the top issues facing industry.

3 Operator Panels

The Subpart H forum opened with two panel discussions:

3.1 Panel A – Current Compliance Challenges & Strategies

This panel consisted of representatives from Fieldwood Energy, Shell, Talos Energy and Chevron. Each company provided a high-level overview of how the new Subpart H requirements are impacting their operations. In addition, each operator discussed strategies and tactics they are currently implementing to achieve compliance.

Common compliance challenges included:

- More time is needed to fully implement the requirements of the new rule.
- Testing of PSVs, and other SPPE equipment, is significant challenge.
- A more specific definition of "failure" is needed to ensure that industry knows what is reportable and how the data collected by BSEE will be utilized.
- Departure requests are a key part of implementing the new requirements, especially in gaining additional time for implementation.
- Subpart H has resulted in one operator creating a position of Operations Compliance Manager to ensure all the requirements of the new rule are implemented.

3.2 Panel B – PSV, Flame Arrestors, Drawings and Other Issues

This panel consisted of representatives from Shell, EnVen and Anadarko. Each company representative provided a more in-depth view of the challenges and compliance techniques for specific parts of the rule.

- Shell discussed PSV testing and how the new rule forces operators (by default) to rely on hearing the main piston valve lift (by sound) to comply with the new testing requirements.
- EnVen discussed conducting flame arrestor inspections utilizing *API Recommended Practice 2210, Flame Arrestors for Vents of Tanks Storing Petroleum Products.*

- Anadarko reviewed issues with the PE certification and stamping requirements under Subpart H; highlighting how many consulting engineering companies see conflicts between the Subpart H requirements and state engineering licensing requirements.

4 Pre-Forum Questions to BSEE & Forum Q&A

Prior to the forum, OOC collected, reviewed, and submitted a list of Subpart H clarification questions to the BSEE Gulf of Mexico Regional Office. These questions were collected from various OOC members, and reviewed by the OOC Subpart H work group prior to submittal to BSEE.

During the forum BSEE representatives reviewed each of the questions along with answers developed by BSEE.

The following BSEE representatives were present at the Forum:

Name	Company
Lars Herbst	GoM Regional Director
Michael Saucier	GoM Regional Supervisor for District Field Operations
Troy Trosclair	GoM Deputy Regional Supervisor for District Field Operations
James Fletcher	Production Coordinator, GoM Region
Steve Dessauer	GoM Production Operations Section Chief
Doug Morris	Chief, Office of Offshore Regulatory Programs, BSEE HQ
Amy White	Chief, Regulations & Standards Branch, BSEE HQ

Messrs. Fletcher, Dessauer, and Trosclair led the Q&A discussion during the forum.

The list of OOC clarification questions are included as Appendix 1.

The BSEE answers reviewed at the forum are included as Appendix 2.

5 Interactive Session

After BSEE completed the Q&A session, the forum participants were divided into 13 small groups. Each group was asked to identify (based on operator panels and BSEE discussions) the Top 5 challenges for industry in implementing the Subpart H requirements. Each team documented their list. OOC staff captured each issue on flip charts that were displayed in the room (duplicate issues were only displayed once).

Twenty-three separate issues were identified and displayed in the forum meeting room. Then, each participant was asked to vote 5 times for the top issues. A participant could vote for 5 separate issues (1 vote each), or the participant could use other combinations of votes, voting up to 5 times for the same issue (i.e. all 5 votes could be cast for 1 issue).

Post-forum, OOC staff analyzed the voting results to better understand what issues the OOC Subpart H work group needs to address moving forward. The charts below summarize the results of the voting.

Chart 1 (bar chart) represents the votes cast for each specific issue identified during the forum. In addition, to each specific challenge, OOC grouped the issues identified into 5 specific categories. These categories are shown on the colored legend on Chart 1 and, also, in the pie cart shown in Chart 2.

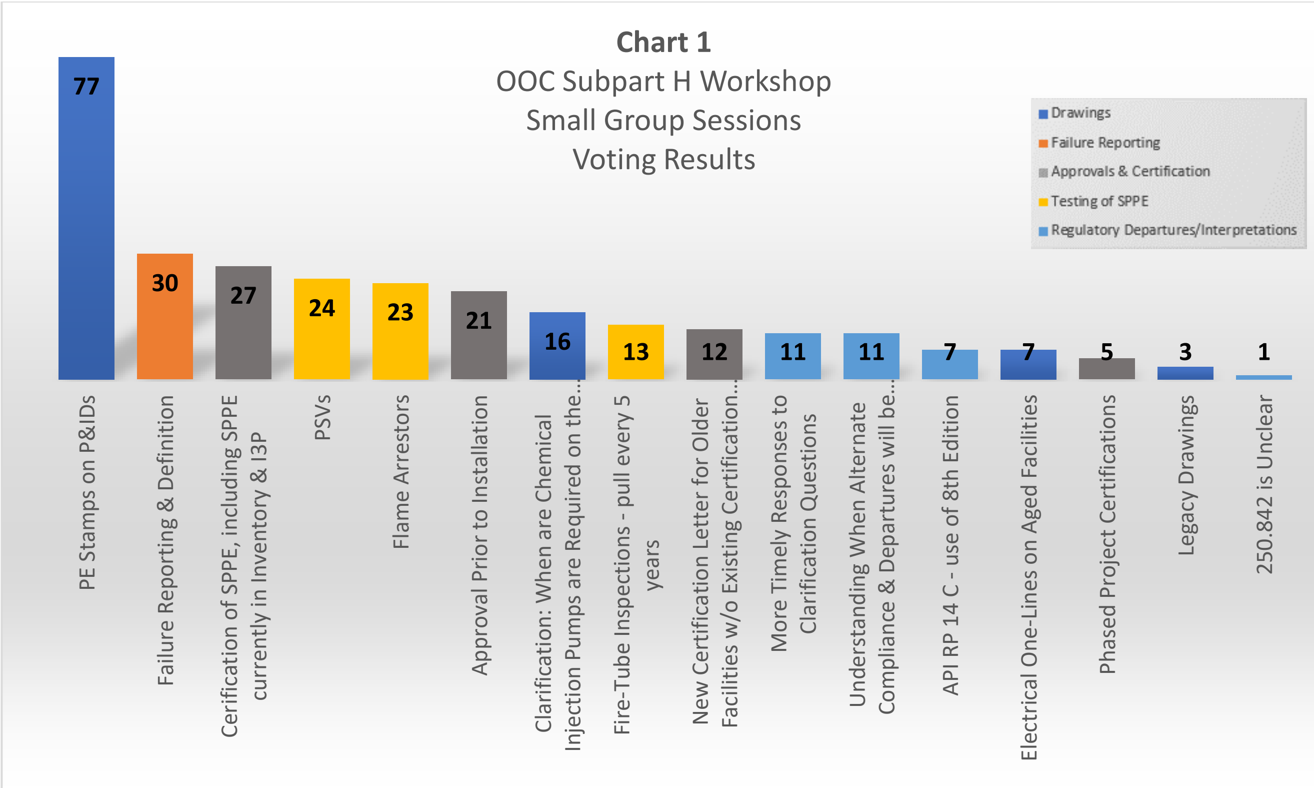
Chart 1
OOC Subpart H Workshop
Small Group Sessions
Voting Results
Drawings
Failure Reporting
Approvals & Certification
Testing of SPPE
Regulatory Departures/Interpretations
77
30
27
24
23
21
16
13
12
11
11
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7
5
3
1
PE Stamps on P&IDs
Failure Reporting & Definition
Cerification of SPPE, including SPPE currently in Inventory & I3P
PSVs
Flame Arrestors
Approval Prior to Installation
Clarification: When are Chemical Injection Pumps are Required on the...
Fire-Tube Inspections - pull every 5 years
New Certification Letter for Older Facilities w/o Existing Certification...
More Timely Responses to Clarification Questions
Understanding When Alternate Compliance & Departures will be...
API RP 14 C - use of 8th Edition
Electrical One-Lines on Aged Facilities
Phased Project Certifications
Legacy Drawings
250.842 is Unclear

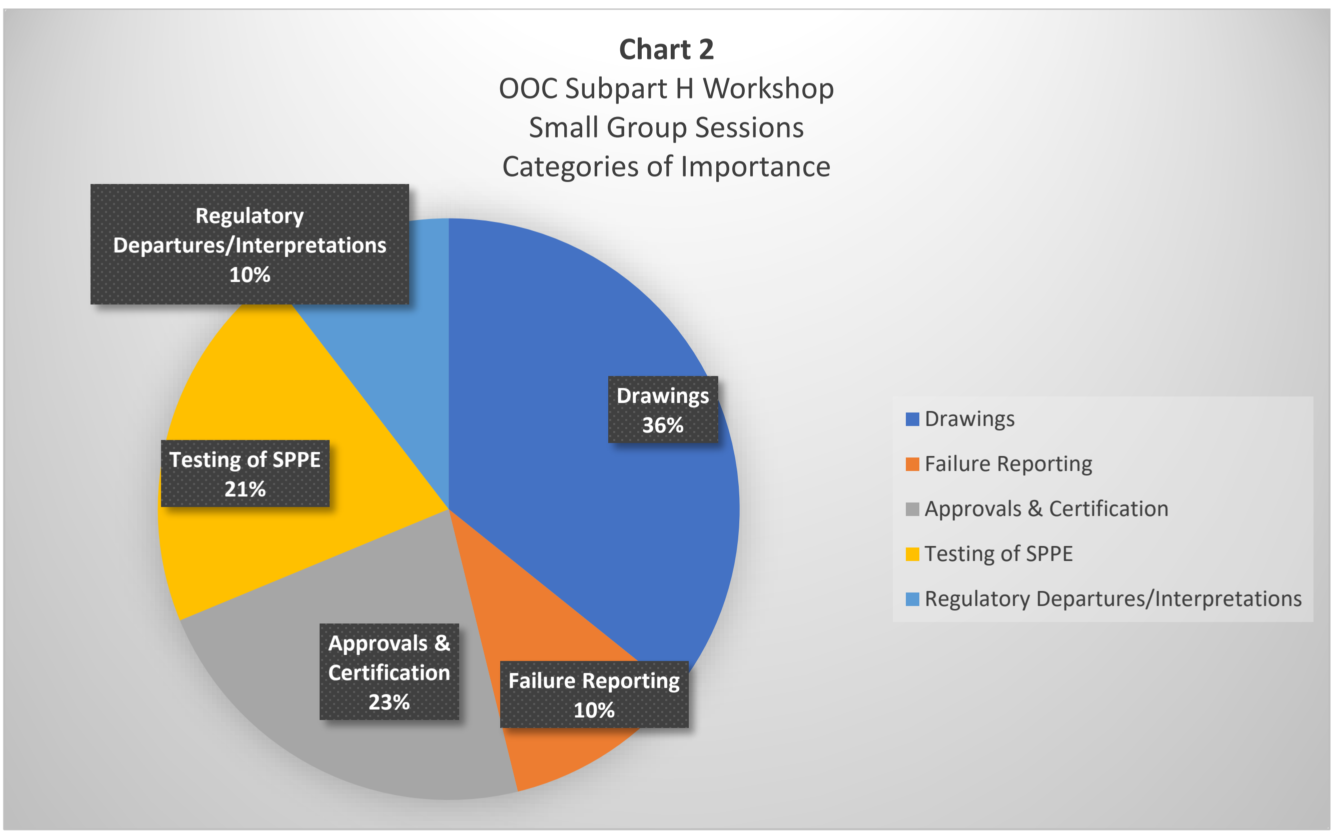


Chart 2
OOC Subpart H Workshop
Small Group Sessions
Categories of Importance
Regulatory Departures/Interpretations 10%
Drawings 36%
Testing of SPPE 21%
Approvals & Certification 23%
Failure Reporting 10%
Drawings
Failure Reporting
Approvals & Certification
Testing of SPPE
Regulatory Departures/Interpretations

6 Observations & Conclusions

Based on the small group work session and voting results summarized above the following observations and conclusions can be made:

1) Key issues and challenges identified prior to the forum in the OOC clarification questions still raise concerns post-forum. These key issues and challenges are:

    - PE stamping and certification of drawings,
    - Testing of SPPE – especially PSVs,
    - The Subpart H "failure definition" and associated reporting requirements, and
    - Clarity around approvals and certifications for offshore projects.

2) The clarifications offered by BSEE in the Q&A session (see Appendix 2) did not provide the level of clarity many operators were seeking. OOC will continue to engage the agency all appropriate levels to seek clarity and consistency on the Subpart H requirements.

7 Forum Registrants

The list consists of the individuals from the oil and gas industry that registered for the forum.

First	Last	Company
Susan	Frizzell	Adley Services, LLC
Adam	Hebert	Anadarko
Dominick	Faraci	Anadarko Petroleum Corporation
Joseph	Gayneaux	Anadarko Petroleum Corporation
Susan	Hathcock	Anadarko Petroleum Corporation
Harold	Pickering	Anadarko Petroleum Corporation
Ronald Jr.	Washington	Anadarko Petroleum Corporation
Casey	Geohegan	ANKOR Energy
Steve	Goff	ANKOR Energy
Ernest	Thibodeaux	ANKOR Energy
Ben	Frederick	Arena Offshore
Connie	Goers	Arena Offshore
Gilbert	Alonzo	BP
Betsy	Cleland	BP
Grace	Cooling	BP
Ted	Judice	BP
Sharrell	McKennie	BP
Beth	Atwood	BP Exploration & Production Inc.
James	Fletcher	BSEE
Doug	Morris	BSEE
Mike	Saucier	BSEE
Troy	Trosclair	BSEE
Amy	White	BSEE
Lawrence	Starlight	BW Offshore
Jonathan	Blanque	CETCO Energy Services
Jim	Miller	CETCO Energy Services
Travis	Potier	CETCO Energy Services
Bennie	Eldred	Cetco Oilfield Services
David	Dykes	Chevron
Michael	Fouchi	Chevron
Joe	Gordon	Chevron
Hogge	Laura	Chevron
Josh	Wilson	Chevron
Phil	Bernard	Compliance Technology Group
Runnels	Charles	Compliance Technology Group
Poticha	Ron	Compliance Technology Group
Michael	Roberts	Cox Operating LLC
Shashikant	Sarada	DNV GL
Mohsen	Shavandi	DNV Gl
Wayne	Page	EDG, Inc.
Gary	Shie	EDG, Inc.
Brady	Tillman	EDG, Inc.
Erik	Phelps	EMPC
Dana	Larson	Energy XXI
Mark	Rogers	Energy XXI
Natalie	Schumann	Energy XXI
Varun	Ullal	Eni Petroleum US
Mike	Dibello	Eni US Operating Co. Inc
Brenda	Montalvo	Eni US Operating Co. Inc.
David	Helminiak	EnVen Energy
John	Martin	EnVen Energy
Silvestre	Olivares	EnVen Energy

First	Last	Company
Cheryl	Powell	EnVen Energy
David	Vasseur	EnVen Energy
Bubba	Breeding	EPIC Management Resources, LLC
Andres	Arana	Expro Group
Stan	Becnel	Expro Group
Kirk	Trascher	EXXI
Bryan	Chapman	Exxon Mobil
Erik	Case	ExxonMobil
Monica	Muzny	ExxonMobil
Vinay	Wagh	ExxonMobil
wiley	smith	ExxonMobil / USP
Broussard	David	Fieldwood Energy
Joel	Plauche	Fieldwood Energy
Brent	Douglas	Genesis Energy, L.P.
Chuck	Hackett	Genesis Energy, L.P.
Todd	Rivera	Genesis Energy, L.P.
Roy	Chisum	HESS Corporation
Brittany	Gill	HESS Corporation
Ron	Marshall	Hess Corporation
Brian	Weydert	LLOG Exploration
Pat	Bernard	M&H Energy Services
Niles	McWilliams	M&H Energy Services
Horst	Jason	Manta Consulting
Sonnier	Brent	Murphy
Mantei	Dave	Murphy
Michael	McDermott	Murphy
James	Robert	Murphy
Benjamin	Daniell	Noble Energy
JD	Davis	Noble Energy
George	Hecker	Noble Energy Inc
Kim	Farmakakis	Noble Energy, Inc.
Deaver	James	O F D Engineering
Luis	Ramirez	OFD Engineering
Jon	Nun	OOC
Greg	Southworth	OOC
Dean	Barnes	Pentair Valves & Controls
Tim	Vosloh	Pentair Valves & Controls
Aubin	Buquet	PetroQuest Energy
Gordon	Laseter	PetroQuest Energy
Tim	Waguespack	PetroQuest Energy
Genny	Broussard	PMB Safety & Regulatory, Inc.
Alex	Alvarado	Project Consulting Services, Inc.
Janet	Cole	Renaissance Offshore
Katherine	Gamble	Renaissance Offshore
Van Nhi	Nguyen	Renaissance Offshore
Tim	Dickensheets	SBM Stones Operations
Mark	Davis	Shamrock Energy Solutions
Theresa	DiCarlo	Shell
Jarrett	Hawkins	Shell
Bill	Terrebonne	Shell
Alicia	Calero	Shell Exploration and Production
David	Lemonier	Shell Exploration and Production
Mark	Greenley	Stone Energy
Brandon	Hebert	Stone Energy
Brian	Saltzman	Stone Energy

First	Last	Company
Cory	Terro	Stone Energy
Steve	Frantz	Talos Energy
Champagne	Steve	Talos GOM, LLC
Kayla	Lehmann	Volunteer
Megan	Martter	Volunteer
Antoine	Gautreaux	W&T Offshore Inc.
Steve	Cole	Whistler Energy II, LLC
Mike	Francis	Whitney Oil & Gas
Brandon	Towle	Williams
Wanda	Parker	WJP Enterprises
John	Cothern	Wood Group
Bryan	Mack	Wood Group
Jan	Rogers	Wood Group
Mike	Sakers	Wood Group
Farrel	Zwerneman	Wood Group

Appendix 1

OOC Clarification Questions to BSEE

Subpart H Clarification Questions

Citation (30 CFR 250…)	Rule Language	Questions
800(b) and (c)	*(b) For all new production systems on fixed leg platforms, you must comply with API RP 14J (incorporated by reference as specified in § 250.198);* *(c) For all new floating production systems (FPSs) (e.g., column-stabilized units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); and spars), you must:* *(1) Comply with API RP 14J;* *(2) Meet the production riser standards of API RP 2RD (incorporated by reference as specified in § 250.198), provided that you may not install single bore production risers from floating production facilities;* *(3) Design all stationkeeping (i.e., anchoring and mooring) systems for floating production facilities to meet the standards of API RP 2SK and API RP 2SM (both incorporated by reference as specified in § 250.198); and* *(4) Design stationkeeping (i.e., anchoring and mooring) systems for floating facilities to meet the structural requirements of §§ 250.900 through 250.921*	250.800 (b) and (c) states new fixed leg platforms and floating production systems must comply with API 14J. API 14 J Table 1 lists Design Aids for process facilities systems and components. Are these design aids a requirement to meet sections 250.800 (b) and (c)? If API 14J Table 1 and Design Aids are not required by 250.800 (b) and (c), please note that the practices in Table 1 are industry practices for design e.g. API 520 and 521 for relief system design, ANSI B31.3 etc. for piping and valves and so forth.
801(a)	*1. SPPE equipment. In wells located on the OCS, you must install only safety and pollution prevention equipment (SPPE) considered certified under paragraph (b) of this section or accepted under paragraph (c) of this section. BSEE considers the following equipment to be types of SPPE:* *(1) Surface safety valves (SSV) and actuators, including those installed on injection wells capable of natural flow;* *(2) Boarding shutdown valves (BSDV) and their actuators, as of September 7, 2017. For subsea wells, the BSDV is the surface equivalent of an SSV on a surface well;* *(3) Underwater safety valves (USV) and actuators; and*	1. 250.801 list SPPE. GLSDV is noted in 250.873 but not in 250.801. What is the reasoning? 2. Is SPPE equipment referred to in 250.801 limited to SSV, BSDV, USV and SSSV? 3. Are WISDV, GLSDV, and other non-hydrocarbon bearing BSDV-type valves subject to the certification requirement? 4. For BSDVs acquired, procured, fabricated, and installed on their respective skids prior to November 2016 when the Subpart H rules took affect for use after 2017, will these BSDVs be required to meet “certification’ requirements if they lack API monogramming but were designed to meet legacy requirements in NTL No. 2009-G36? Assuming these brand new valves require no repair of any

Citation (30 CFR 250…)	Rule Language	Questions
	(4) Subsurface safety valves (SSSV) and associated safety valve locks and landing nipples.	kind.
801(b)	*(b) Certification of SPPE. SPPE that is manufactured and marked pursuant to ANSI/API Spec. Q1 (incorporated by reference as specified in § 250.198), is considered as certified SPPE under this part. All other SPPE is considered as not certified, unless approved in accordance with paragraph (c) of this section.*	Does the certification requirement of SPPE equipment referred to in 250.801 (b) include the actuator or is it limited to the valve?
801(c)	*(c) Accepting SPPE manufactured under other quality assurance programs. BSEE may exercise its discretion to accept SPPE manufactured under a quality assurance program other than ANSI/API Spec. Q1, provided that the alternative quality assurance program is verified as equivalent to API Spec. Q1 by an appropriately qualified entity and that the operator submits a request to BSEE containing relevant information about the alternative program and receives BSEE approval. In addition, an operator may request that BSEE accept SPPE that is marked with a third-party certification mark other than the API monogram. All requests under this paragraph should be submitted to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; VAE–ORP; 45600 Woodland Road, Sterling, VA 20166.*	Would adherence to ISO 290001 be considered alternate compliance?
802(a)	*(a) All SSVs, BSDVs, and USVs and their actuators must meet all of the specifications contained in ANSI/API Spec. 6A and API Spec. 6AV1 (both incorporated by reference as specified in § 250.198).*	1. Does a BSDV that undergoes inline repairs or actuator change outs, need to meet the requirements in 250.802? 2. For 250.802 (a), does BSEE intend to apply API 6A, Specification, for Wellhead and Christmas Tree Equipment to topsides boarding valves?
802(c)	*(c) Requirements derived from the documents incorporated in this section for SSVs, BSDVs, USVs, and SSSVs and their actuators, include, but are not limited to, the following:* *(1) Each device must be designed to function and to close in the most*	1. Does extreme condition include fire rating conditions for the valve and actuators?

Citation (30 CFR 250…)	Rule Language	Questions
	extreme conditions to which it may be exposed, including temperature, pressure, flow rates, and environmental conditions. You must have an independent third-party review and certify that each device will function as designed under the conditions to which it may be exposed. The independent third-party must have sufficient expertise and experience to perform the review and certification. *(2) All materials and parts must meet the original equipment manufacturer specifications and acceptance criteria.* *(3) The device must pass applicable validation tests and functional tests performed by an API-licensed test agency.* *(4) You must have requalification testing performed following manufacture design changes.* *(5) You must comply with and document all manufacturing, traceability, quality control, and inspection requirements.* *(6) You must follow specified installation, testing, and repair protocols.* *(7) You must use only qualified parts, procedures, and personnel to repair or redress equipment.*	2. 250.802(c)(4) requires “requalification testing performed following manufacturing design changes”. The API documents distinguish between substantive and non-substantive changes and require this requalification testing only for substantive changes. We are seeking clarification that we do not need to perform requalification testing for minor, non-substantive changes. 3. Independent 3rd party certification of SPPE. Request clarification that this requirement applies to new equipment installed or modified after the effective date of the rule, and not to existing in-service equipment.
803(a)	*(a) You must follow the failure reporting requirements contained in section 10.20.7.4 of API Spec. 6A for SSVs, BSDVs, and USVs and section 7.10 of API Spec. 14A and Annex F of API RP 14B for SSSVs (all incorporated by reference in §250.198). You must provide a written notice of equipment failure to the Chief, Office of Offshore Regulatory Programs or to the Chief's designee and to the manufacturer of such equipment within 30 days after the discovery and identification of the failure. A failure is any condition that prevents the equipment from meeting the functional specification or purpose.*	Define failure as proposed - SPPE required to be reported and investigated is defined as a failure that prevents the SPPE from performing to the requirements of the functional specification or purpose **whereas remediation requires offsite repair, re-manufacturing, or any hot work such as welding.** Below is from BSEE comments in *Federal Register* / Vol. 81, No. 173 / Wednesday, September 7, 2016 / Rules and Regulations The final rule defines a failure as, “any condition that prevents the equipment from meeting the functional specification.” This is intended to **ensure that design defects are identified and corrected** and that equipment is replaced before it fails.
803(b)	*(b) You must ensure that an investigation and a failure analysis are performed within 120 days of the failure to determine the cause of the*	1. What if you shut-in to be safe but are unable to remove the valve within the 120 days?

Citation (30 CFR 250…)	Rule Language	Questions
	failure. If the investigation and analyses are performed by an entity other than the manufacturer, you must ensure that manufacturer and the Chief, Office of Offshore Regulatory Programs or the Chief's designee receives a copy of the analysis report. You must also ensure that the results of the investigation and any corrective action are documented in the analysis report.	2. When does "the 120-day clock start" – when you notice the failure or when you retrieve the component? For example, for subsea wells, may not be able to retrieve the SSSV that quickly.
805(a)	*(a) In zones known to contain hydrogen sulfide (H2S) or in zones where the presence of H2S is unknown, as defined in § 250.490, you must conduct production operations in accordance with that section and other relevant requirements of this subpart.*	For 805 (a), if the reservoir is to be waterflooded and as a consequence may become sour, does this paragraph apply?
820	*You must install, maintain, inspect, repair, and test all SSVs in accordance with API RP 14H (incorporated by reference as specified in § 250.198). If any SSV does not operate properly, or if any gas and/or liquid fluid flow is observed during the leakage test as described in § 250.880, then you must shut-in all sources to the SSV and repair or replace the valve before resuming production.*	250.820 requires surface tree valves (SSVs) to be tested in accordance with API RP 14H which allows a 400 cc/min liquid leakage rate. 250.834 requires subsea tree valves (USVs) be tested in accordance with API RP 14H which has the same criteria for USVs as for SSVs. The tables in Section 250.880(c)(2) and (c)(4) provide the same leakage criteria as API RP 14H for USVs but 880(c)(2)(iv) specifies "If an SSV does not operate properly or if any gas and/or liquid fluid flow is observed during the leakage test, the valve must be immediately repaired or replaced." There appears to be a conflict between the provisions in the table and the provisions in API RP 14H. Please clarify that the API RP 14H allowable leakage rate applies for the pressure controlling aspect of the valve but "no leakage" applies for only the pressure containing aspect of the SSV as described in API RP 14H?
825(b)	*(b) After installing the subsea tree, but before the rig or installation vessel leaves the area, you must test all valves and sensors to ensure that they are operating as designed and meet all the conditions specified in this subpart.*	Please clarify that 825(b) applies only to SSSVs and sensors related to the SSSVs, and not more broadly to all valves and sensors on a subsea tree.
826	*All SSSVs, safety valve locks, and landing nipples installed on the OCS must conform to the requirements specified in §250.801 through 250.803 and any Deepwater Operations Plan (DWOP) required by §250.286*	SCSSV needs to meet requirements of 250.801 to 250.803 and any DWOP. In the event of a conflict of regulations and DWOP, which

Citation (30 CFR 250…)	Rule Language	Questions
	through 250.295.	takes precedence?
828(b)	*(b) The well must not be open to flow while an SSSV is inoperable, unless specifically approved by the District Manager in an APM.*	What is the definition of inoperable in this section?
835(b)	*(b) Use a BSDV that is fire rated for 30 minutes, and is pressure rated for the maximum allowable operating pressure (MAOP) approved in your pipeline application.*	The regulation states the BSDV must be fire rated for 30 minutes, does this include the actuator or if the actuator fails to a safe position is that adequate?
835(c)	*(c) Locate the BSDV within 10 feet of the first point of access to the boarding pipeline riser (i.e., within 10 feet of the edge of platform if the BSDV is horizontal, or within 10 feet above the first accessible working deck, excluding the boat landing and above the splash zone, if the BSDV is vertical).*	How would this paragraph be interpreted if a platform's horizontal BSDVs are within 10' of penetration but not on edge of platform?
841(a)	*(a) You must protect all platform production facilities with a basic and ancillary surface safety system designed, analyzed, installed, tested, and maintained in operating condition in accordance with the provisions of API RP 14C (incorporated by reference as specified in § 250.198). If you use processing components other than those for which Safety Analysis Checklists are included in API RP 14C, you must utilize the analysis technique and documentation specified in API RP 14C to determine the effects and requirements of these components on the safety system. Safety device requirements for pipelines are contained in § 250.1004.*	This statement gives the latitude to use the Safety Analysis Checklists to not install certain equipment; however the rule has included several direct extracts from 14C as requirements with no corresponding ability to meet thru alternate means as the Safety Analysis Checklists. Examples include 250.858 where the PSH, PSL, LSH and TSH are identified specifically without regard to the compressor type or material selected. This defaults you to an instrumented protection system rather than an inherently safe design. *Suggestion:* Specify that API RP 14C (as incorporated by reference) that you are still able to utilize all the options provided in the development of the Safety Analysis Checklists.
841(b)	*(b) You must design, install, inspect, repair, test, and maintain in operating condition all platform production process piping in accordance with API RP 14E and API 570 (both incorporated by reference as specified in § 250.198). The District Manager may approve temporary repairs to facility piping on a case-by-case basis for a period not to exceed 30 days.*	In the past, platforms have been approved for temporary repairs (clamps) for periods of several years. What types of temporary repairs will be allowed under the new rule? Also, please differentiate between temporary repairs for integrity issues that have leaked already vs. temporary repairs used for preventative measures.

<table>
<tr><th>Citation (30 CFR 250…)</th><th>Rule Language</th><th>Questions</th></tr>
<tr>
<td>842(a)</td>
<td>(a) Before you install or modify a production safety system, you must submit a production safety system application to the District Manager for approval. The application must include the information prescribed in the following table:
<table>
<tr><td>You must submit:</td><td>Details and/or additional requirements:</td></tr>
<tr><td>(1) A schematic piping and instrumentation diagram…</td><td>Showing the following:</td></tr>
<tr><td></td><td>(i) Well shut-in tubing pressure;</td></tr>
<tr><td></td><td>(ii) Piping specification breaks, piping sizes;</td></tr>
<tr><td></td><td>(iii) Pressure relief valve set points;</td></tr>
<tr><td></td><td>(iv) Size, capacity, and design working pressures of separators, flare scrubbers, heat exchangers, treaters, storage tanks, compressors and metering devices;</td></tr>
<tr><td></td><td>(v) Size, capacity, design working pressures, and maximum discharge pressure of hydrocarbon handling pumps;</td></tr>
<tr><td></td><td>(vi) size, capacity, and design working pressures of hydrocarbon-handling vessels, and chemical injection systems</td></tr>
</table>
</td>
<td>1. On a modification to a facility, are you allowed to make connections with (locked closed valves with skillets installed) prior to BSEE approving the modification submittal? The regulations don't say anything about tie-ins or connections. The regulations do make it clear 250.842 Before you install or modify a production safety system, you must submit a production safety system application to the District Manager for approval. The regulations also make it clear that you may conduct the installation prior to receiving BSEE approval, 250.800 You must not commence production until BSEE approves your production safety system application and you have requested a preproduction inspection. 250.869 When pressure or atmospheric vessels are isolated from production facilities (e.g. inlet valve locked closed or inlet blind-flanged) and are to remain isolated for an extended period of time, safety device testing in accordance with API RP 14C is not required with the exception of the PSV.

2. 250.842(a)(1), (3) and (4) Electrical and Fire & Gas detection schematics:

Do P&IDs held for non-14C changes and submitted at the end of the year require a PE stamp on each cloud?
How will electrical one-lines be addressed? Similar to minor, non API 14C drawings with an annual update? What would be considered "major" such that an approval is required? Are there any major changes that need to be submitted for approval?
Which documents need to be submitted to meet (3) Electrical System Information and (4) Schematics of the fire and gas-detection systems? Please provide example list.
Do the Fire & Gas loop drawings need to be submitted with the other F&G drawings as other drawings include similar information.

3. What does BSEE mean with "Identification of all areas where potential ignition sources are to be installed" 250.842 table (3) (ii). Is this part of (i) "Plan outlining all classified areas" and "one-line</td>
</tr>
</table>

<table>
<tr><th>Citation (30 CFR 250…)</th><th colspan="2">Rule Language</th><th>Questions</th></tr>
<tr><td rowspan="5"></td><td></td><td>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).</td><td rowspan="5">drawings"? Or is BSEE looking for a separate list with installed electrical equipment in hazardous areas?

4. General questions regarding applications
• Does replacement in kind need to be submitted for approval?
• Does "you" mean Operator must certify or also ok for Operator employed 3rd party contractor to certify?
• For preproduction certification, What minimum information needs to provided here? Is this just as simple as "I, Joe Smith, certify that xyz was installed in accordance with BSEE approved design"?
• Do we need to wait for any form of BSEE acknowledgement that this certification was received by them before we can start production?
• Would like to confirm that the installation certification is to be submitted with the as-built submittal.

5. General questions regarding PE stamps
• Does BSEE accept modified documents with a PE stamp only covering the latest change, i.e. no PE stamp for original drawing?
• Do test spread design drawings need to be stamped by PE? Test spread is typically third party rental kit.

6. Concern: design of future submittals finalized before compliance date
• Will BSEE accept drawings (P&IDs) without a PE stamp for as-built documents, when the original submittal to BSEE was before the compliance date?
• Will BSEE accept drawings without a PE stamp that were engineered and finalized (Issued-for-Construction) before the compliance date, but submitted to BSEE after the compliance date?</td></tr>
<tr><td></td><td>(vii) Size and maximum allowable working pressures as determined in accordance with API RP 14E, (incorporated by reference as specified in § 250.198).</td></tr>
<tr><td>(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).</td><td>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.</td></tr>
<tr><td>(3) Electrical system information, including …</td><td>(i) A plan for each platform deck and outlining all classified areas. You must classify areas according to API RP 500 or API RP 505 (both incorporated by reference as specified in § 250.198)</td></tr>
<tr><td></td><td>(ii) Identification of all areas where potential ignition sources, including non-electrical ignition</td></tr>
</table>

Citation (30 CFR 250…)	Rule Language		Questions
		sources, are to be installed showing:	7. Changes to P&IDs and other documents are frequent and often minor. • What size/kind of changes need a PE stamp? Only the ones requiring a HAZOP? • What size/kind of changes need to be submitted to BSEE? 8. Does BSEE expect PE stamps on any drawings other than the ones explicitly called out in 250.842 table: P&ID, Safety Analysis Flow Diagram, Safety Analysis Function Chart, plan outlining all classified areas, one-line electrical drawings, and schematics of fire and gas-detection systems? 9. If there are only drafting updates on a P&ID (no change to design or install/modification of production safety system), do those changes need to be PE stamped and/or submitted to BSEE?
		(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.*	

Citation (30 CFR 250…)	Rule Language	Questions
	(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.*	
842(b)	*(b) In the production safety system application, you must also certify the following:* *(1) That all electrical installations were designed according to API RP 14F or API RP 14FZ, as applicable (incorporated by reference as specified in § 250.198);* *(2) That the designs for the mechanical and electrical systems under paragraph (a) of this section were reviewed, approved, and stamped by an appropriate registered professional engineer(s). The registered professional engineer must be registered in a State or Territory of the United States and have sufficient expertise and experience to perform the duties; and* *(3) That a hazards analysis was performed in accordance with § 250.1911 and API RP 14J (incorporated by reference as specified in § 250.198), and that you have a hazards analysis program in place to assess potential hazards during the operation of the facility.*	1. What is the extent of the meaning of electrical systems? To what level of detail is the Electrical System to be stamped? Does this include the reports and each individual single line, cable tray drawings etc. 2. What is meant by mechanical systems and to what level of detail must the mechanical design be stamped? Is this the base process design and PFDs and P&IDs or again do we go into the details of the design such as the PSV-sizing basis, design calculations and vendor supplied actual device rating calculations? What about ASME vessel, these can be purchased worldwide to ASME code? Designs for these vessels generally do not have a PE stamp. It is a subset of the base design.
851(a)	*(a) Pressure vessels (including heat exchangers) and fired vessels supporting production operations must meet the requirements in the following table:* *Item name* — *Applicable codes and requirements* *(1) Pressure and fired vessels* — *(i) Must be designed, fabricated, and code stamped according to applicable provisions of sections I, IV, and VIII of the ANSI/ASME Boiler and Pressure Vessel Code (incorporated by reference as*	1. The BSEE rule and ASME PV code are not consistent. The ASME code has additional exclusions from code stamping beyond that mentioned in BSEE requirements, thus a vessel that is exempt from ASME Section VIII, by the CFR would still need to be code stamped. For all future pressure vessel procurement, BP would have to require all pressure vessels to be designed and constructed to ASME pressure vessel code. What would be acceptable justification for operation of uncoded equipment beyond March 1, 2018? 2. ANSI/ASME Boiler and Presser Vessel Code, Section I is incorporated by reference in Section 250.851 and 250.1639(b).

Citation (30 CFR 250…)	Rule Language		Questions
		specified in § 250.198).	Section 851(a)(3) states pressure relief must be designed and installed according to applicable provisions in ASME Boiler and Pressure Code. The word "maintained" has been removed from section 851. What is the requirement for maintenance? The boiler and pressure vessel code only requires testing and does not mention PSV maintenance requirements. 3. Please clarify which PSVs fall under the annual testing requirement. Is the annual testing limited to only those PSVs that fall under API 14C requirements? Some PSVs fall under USCG jurisdiction are tested under USCG requirements. However, there are some PSVs on facilities that do not fall in either category. 4. Subpart H does not contain any requirement for overhauling of PSVs. API RP 570 defines a RBI test interval for pressure relief devices. However API RP 570 is not incorporated by reference in any documentation related to pressure relief valve maintenance. *Suggestion:* Incorporate by reference API RP 570 into Sections 250.851(a)(3) 250.1639(b)(i) for pressure relieve maintenance. API RP 570 requires relief valves in hydrocarbon services must be overhauled every 5 years and relief valves in non-hydrocarbon service must be overhauled every 10 years. 5. Section 851(a)(3)(ii) states that you must conform to the valve sizing and pressure-relieving requirements specified in ASME Boiler and Pressure Vessel Code incorporated by reference. However the ASME Boiler code references other documents such as API 520/521 which are not incorporated by reference. API RP 520 and API RP 521 are also referenced in Table 1 of API 14J. Is API RP 520 and 521 a legal requirement because it is referenced as a requirement in the incorporated by reference
		(ii) Must be repaired, maintained, and inspected in accordance with API 510 (incorporated by reference as specified in § 250.198).	
	(2) Existing uncoded pressure and fired vessels (i) in use on November 7, 2016; (ii) with an operating pressure greater than 15 psig; 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 after March 1, 2018.*	
	(3) Pressure relief valves	*(i) Must be designed and installed according to applicable provisions of sections I, IV, and VIII of the ASME Boiler and Pressure Vessel Code (incorporated by reference as specified in § 250.198).*	
		(ii) Must conform to the valve sizing and pressure-relieving requirements specified in these documents, but must be set no higher than the maximum-allowable working pressure of the vessel (except for cases where staggered set pressures are required for configurations using multiple relief valves or redundant valves installed and designated for operator use only).	
		(iii) Vents must be positioned in such a way as to prevent fluid from striking personnel or ignition	

<table>
<tr><th>Citation (30 CFR 250…)</th><th>Rule Language</th><th>Questions</th></tr>
<tr><td></td><td><table><tr><td></td><td>sources.</td></tr></table></td><td>document?</td></tr>
<tr><td>852(c)(1)</td><td>(c) If a well flows directly to a pipeline before separation, the flowline and valves from the well located upstream of and including the header inlet valve(s) must have a working pressure equal to or greater than the maximum shut-in pressure of the well unless the flowline is protected by one of the following:

(1) A relief valve which vents into the platform flare scrubber or some other location approved by the District Manager. You must design the platform flare scrubber to handle, without liquid hydrocarbon carryover to the flare, the maximum-anticipated flow of hydrocarbons that may be relieved to the vessel; or</td><td>Regulations states that you must design the flare scrubber to handle, without liquid hydrocarbon carryover to the flare, the maximum anticipated flow of hydrocarbon that may be relieved to the vessel. There needs to be a time element associated with this requirement otherwise the flare scrubber will be large and unpractical. Is this requirement of flare scrubber sizing limited to the case of only when the well flow directly to a pipeline without separation on the topsides?

Suggestion:

Specify that the flare scrubber must have the capacity to contain the maximum anticipated flow of hydrocarbon for 45 second duration from the time the high-level trip in the flare scrubber is activated. The 45 seconds is based on the BSDV closure time.</td></tr>
<tr><td>855(b)</td><td>(b) You must maintain a schematic of the ESD that indicates the control functions of all safety devices for the platforms on the platform, at your field office nearest the OCS facility, or at another location conveniently available to the District Manager, for the life of the facility.</td><td>The rule requires that a schematic of the ESD, indicating the control functions of all safety devices for the platforms, must be kept on the platform, at the field office nearest the OCS facility, or at another location conveniently available to the District Manager for the life of the facility.

Is BSEE asking for a new document or will the existing SAFE chart suffice as they have much the same information? Additionally a lot of this info is duplicated on P&IDs and Cause and Effects.</td></tr>
<tr><td>872(b)</td><td>(b) You must ensure that all atmospheric vessels are designed and maintained to ensure the proper working conditions for LSH sensors. The LSH sensor bridle must be designed to prevent different density fluids from impacting sensor functionality. For atmospheric vessels that have oil buckets, the LSH sensor must be installed to sense the level in the oil bucket.</td><td>Are pressure vessels operating at atmospheric treated the same way as an atmospheric vessel?</td></tr>
<tr><td>874(g)(1)</td><td>You must test your injection valves as provided in the following table:<table><tr><td>Valve</td><td>Allowable Leakage Rate</td><td>Testing Frequency</td></tr></table></td><td>Clarification if the water injection testing requirements only apply to WI systems after the effective date of the rule or do they apply to existing systems as well.</td></tr>
</table>

Citation (30 CFR 250…)	Rule Language	Questions
	(i) WISDV — *Zero leakage* — *Monthly, not to exceed 6 weeks between tests.* *(ii) Surface-controlled SSSV or WIV* — *400 cc per minute of liquid or 15 scf per minute of gas`* — *Semi-annually, not to exceed 6 calendar months between tests.*	
876	*No later than September 7, 2018, and at least once every 5 years thereafter, you must have a qualified third-party remove and inspect, and then you must repair or replace, as needed, the fire tube for tube-type heaters that are equipped with either automatically controlled natural or forced draft burners installed in either atmospheric or pressure vessels that heat hydrocarbons and/or glycol. If removal and inspection indicates tube-type heater deficiencies, you must complete and document repairs or replacements. You must document the inspection results, retain such documentation for at least 5 years, and make the documentation available to BSEE upon request.*	It states that the "fire tube for tube-type heaters that are equipped with either automatically controlled natural or forced draft burners" must be inspected and repaired every 5 years. The title and the content are inconsistent. Based on the text content, are we to conclude this applies only to fired type heaters and thus exclude waste heat exhaust heaters on power turbines?
880(b)(3)(iii)(B)	*(B) Electronic based ESD systems must be tested for operation at least once every 3 calendar months, not to exceed 120 days between tests. The test must be conducted by alternating ESD stations to close at least one wellhead SSV and verify a surface-controlled SSSV closure for that well as indicated by control circuitry actuation. All stations must be checked for functionality at least once every 3 calendar months, not to exceed 120 days between checks. No station may be reused until all stations have been tested.*	Please clarify what is required to test the ESD logic.
880 (c)(2)(i) Testing frequencies	*PSVs - Annually, not to exceed 12 calendar months between tests. Valve must either be bench-tested or equipped to permit testing with an external pressure source. Weighted disc vent valves used as PSVs on atmospheric tanks may be disassembled and inspected in lieu of function testing. The main valve piston must be lifted during this test.*	Please clarify what types of alternate compliance methods for this requirement may be acceptable. Many offshore locations that not designed to test in this manner. Design philosophies adopted over many years disallowed the installation of block valves under PSVs to eliminate the possibility of inadvertent shutting of block valves rendering PSVs out of service. BSEE/MMS over many years seemed to promote this philosophy. Additionally, this regulation did not undergo economic analysis, many locations require extensive retrofitting to

Citation (30 CFR 250…)	Rule Language	Questions
		achieve this compliance specifically related to pilot operated PSVs.
880 (c)(3)(viii)	*Flame, spark, and detonation arrestors Must be visually inspected annually, not to exceed 12 calendar months between inspections.*	Please clarify on when this must be done.
PINC No. P-451 procedure 7	*states to verify that the PSV is stamped or marked in accordance with ASME Boiler and Pressure Vessel code.*	Please clarify that this should only apply to PSV's installed on ASME stamped vessels. Some PSV's that fall under API 14C are protecting atmospheric vessels or process piping and these do not require PSV's that are ASME stamped.

Appendix 2

BSEE Q&A Presented at OOC Subpart H Forum

Bureau of Safety and Environmental Enforcement

Subpart H Forum - BSEE Q and A

James Fletcher

Production Coordinator, Gulf of Mexico Region

March 28, 2017

"To promote safety, protect the environment and conserve resources offshore through vigorous regulatory oversight and enforcement."

BSEE Mission Statement

"To promote safety, protect the environment and conserve resources offshore through vigorous regulatory oversight and enforcement."

Subpart H Forum – BSEE Q and A

Changes to Regulations

Revisions to:
Code of Federal Regulations

Title 30	Mineral Resources
Chapter II	Bureau of Safety and Environmental Enforcement Department of the Interior
Subchapter B	Offshore
Part 250	Oil and Gas and Sulfur Operations in the Outer Continental Shelf
Subpart H	Oil and Gas Production Safety System

Went into effect November 7, 2016

Subpart H Forum – BSEE Q and A

Exceptions

Boarding Shutdown Valves associated with subsea tiebacks and their actuators will be considered Safety and Pollution Prevention Equipment (SPPE) effective September 7, 2017.

Existing pressure and fired vessels that BSEE deems un-coded (do not have markings of the certification stamp on the name plate, the name plate is missing, or name plate is illegible) that are in use as of November 7, 2016, must be justified and receive District Manager approval by March 1, 2018.

All new firewater pumps installed after November 7, 2017 must have automatic starting capabilities upon the activation of an ESD, function bleed of a fusible loop, or function trip of other fire detection system.

Subpart H Forum – BSEE Q and A

Drawings – P&ID

BSEE will accept in a permit package a Safety Flow Diagram drawing that includes the items listed in 250.842(a)(1) as a combination document (SFD/P&ID) when conducting its safety system review.

NOTE: This should not be construed as BSEE restricting or directing industry in the current industry practices of P&ID development utilized in design, construction, and hazard analysis. These P&IDs must be maintained at a secure onshore location and readily available offshore for BSEE.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.800(b) and (c) – Design aids in industry standards
Question	Section 250.800(b) and (c) states new fixed leg platforms and floating production systems must comply with API 14J. API 14 J Table 1 lists Design Aids for process facilities systems and components. Are these design aids a requirement to meet sections § 250.800(b) and (c)? If API RP 14J, Table 1 and Design Aids are not required by § 250.800(b) and (c), please note that the practices in Table 1 are industry practices for design, e.g., API 520 and 521 for relief system design, ANSI B31.3 etc. for piping and valves and so forth.
Answer	Table 1 in API RP 14J is an aid and provides no specific equipment requirements. Specific facility and equipment requirements are outlined in the regulations, including the standards incorporated by reference at § 250.198. Many of the documents in Table 1 are specifically incorporated in BSEE's regulations. Although only standards incorporated by reference are regulatory requirements, at times compliance with these standards calls for satisfaction of other requirements. For example, documents that are essential in meeting the requirement of the incorporated standard should be adhered to in order to be in compliance with the regulation. *Note: The CFR citations listed in API RP 14J, Table 1 may not be accurate.*

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic

§ 250.801(a) – GLSDV

Question

Section 250.801 lists SPPE. GLSDV is noted in 250.873 but not in 250.801. What is the reasoning?

Answer

Sections 250.873(b)(1), (b)(2) and (b)(3) state that the GLSDV must meet all requirements for the boarding shutdown valve (BSDV) outlined in §§ 250.835 and 250.836. Further, § 250.835 requires that all new BSDVs and BSDVs removed from service for remanufacturing or repair meet the requirements in § 250.801. The GLSDV is the valve immediately upon boarding the host facility from a subsea well, manifold, or riser being lifted. Since USVs are allowed a leakage rate and Gas Lift Isolation valves are not required to have a leakage test done on them, the boarding valve (GLSDV) is the barrier required to be tested bubble tight thereby serving the same purpose as that of the Process Flow Boarding SDV and should be treated as such

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.801(a) – Other equipment considered SPPE
Question	Is SPPE equipment referred to in § 250.801 limited to SSV, BSDV, USV and SSSV?
Answer	No, the list is not intended to be exclusive of other types of safety and pollution prevention equipment, and other sections of the regulations may reference this section for guidance. For example: §§ 250.873(b)(1), (b)(2) and (b)(3) state that the GLSDV must meet all requirements for the BSDV outline in §§ 250.835 and 250.836, including, the requirement to satisfy § 250.801.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.801(a) – Certification requirements
Question	Are WISDV, GLSDV, and other non-hydrocarbon bearing BSDV-type valves subject to the certification requirement?
Answer	The GLSDV requirements at §§ 250.873(b) and 250.835 require compliance with §§ 250.801-250.802. Therefore GLSDVs must be certified under those regulations. However, the WISDV requirements do not reference §§ 250.801-250.803, so such equipment is not required to be certified. If any other requirements for BSDV-type valves reference §§ 250.801-250.802, then they are required to be certified.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.801(a) – Non-certified SPPE
Question	For BSDVs acquired, procured, fabricated, and installed on their respective skids prior to November 2016 when the Subpart H rules took affect for use after 2017, will these BSDVs be required to meet "certification' requirements if they lack API monogramming but were designed to meet legacy requirements in NTL No. 2009-G36? Assuming these brand new valves require no repair of any kind.
Answer	SPPE must be installed and used according to the requirements of § 250.802(d). The certification requirements for BSDVs in § 250.801(a)(2) do not take effect until September 7, 2017. At that point, pursuant to § 250.835, the requirements of §§ 250.801-250.803 apply only to new BSDVs and BSDVs removed from service for remanufacturing or repair. "[O]perators may continue to use any existing non-certified SPPE already in service unless and until it needs offsite repair, remanufacture or hot work. In addition, [because] final § 250.801 includes BSDVs as SPPEs (beginning September 7, 2017), the final rule provides that operators have until that date to come into compliance with the certification requirements for any new BSDVs; moreover, under final § 250.802(d), currently installed non-certified BSDVs may remain in service unless and until they require offsite repair, remanufacture or hot work." Final rule preamble, 81 FR 61858.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.801(b) – Actuator certification
Question	Does the certification requirement of SPPE equipment referred to in § 250.801(b) include the actuator or is it limited to the valve?
Answer	Certification is required for the actuators as specified in §§ 250.801(a)(1), (2), and (3).

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic § 250.801(c) – Other quality assurance programs

Question Would adherence to ISO 290001 be considered alternate compliance?

Answer ISO 290001 may be considered as an alternative quality assurance program. This would require you to follow the requirements outlined in § 250.801(c).

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.802(a) – Inline repairs
Question	Does a BSDV that undergoes inline repairs or actuator change outs, need to meet the requirements in § 250.802?
Answer	250.801(a)(2) lists BDSV actuators as SPPE. 250.802(d)(1) and (d)(3) require the installation of certified SPPE if it is repaired offsite, remanufactured, or subject to hot work. If an actuator change out involves one of these operations (i.e., offsite repair, remanufacture, or hot work), you must install a certified actuator.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.802(a) – API Spec. 6A
Question	For § 250.802(a), does BSEE intend to apply API Spec. 6A, Specification, for Wellhead and Christmas Tree Equipment to topsides boarding valves?
Answer	API Spec. 6A applies to all BSDVs.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.802(c) – Fire rating
Question	Does extreme condition include fire rating conditions for the valve and actuators?
Answer	The valve must be able to close and hold for a minimum of 30 minutes in a fire rating condition.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic

§ 250.802(c)(4) – Requalification testing

Question

Section 250.802(c)(4) requires "requalification testing performed following manufacturing design changes." The API documents distinguish between substantive and non-substantive changes and require this requalification testing only for substantive changes.

We are seeking clarification that we do not need to perform requalification testing for minor, non-substantive changes.

Answer

Substantive changes require requalification testing. Substantive changes are those defined by API Spec. 6A and API Spec. 14A. Minor, non-substantive changes do not require requalification testing. For a design change to be considered "non-substantive" the design change must be approved by a qualified person other than the person performing the requalification testing, and records of the results will become a portion of the design documentation.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.802(c)(1) – Independent 3rd party review and certification
Question	Request clarification that this requirement applies to new equipment installed or modified after the effective date of the rule, and not to existing in-service equipment.
Answer	BDSVs and their actuators installed after Sept. 7, 2017, must be certified. 250.801(a)(2). SSVs, USVs, SSSVs and their actuators installed after Nov. 7, 2016, must be certified. 250.801(a)(1), (3), and (4). Modified equipment is addressed in § 250.802(d)(3).

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.803(a) – Failure definition
Question	Define failure as proposed - SPPE required to be reported and investigated is defined as a failure that prevents the SPPE from performing to the requirements of the functional specification or purpose whereas remediation requires offsite repair, re-manufacturing, or any hot work such as welding. Below is from BSEE comments in Federal Register / Vol. 81, No. 173 / Wednesday, September 7, 2016 / Rules and Regulations The final rule defines a failure as, "any condition that prevents the equipment from meeting the functional specification." This is intended to ensure that design defects are identified and corrected and that equipment is replaced before it fails.
Answer	BSEE disagrees; 250.803(a) establishes the definition of failure with respect to SPPE reporting: "A failure is any condition that prevents the equipment from meeting the functional specification or purpose." This is the definition of "failure" that BSEE uses.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.803(b) – Failure analysis timetable
Question	What if you shut-in to be safe but are unable to remove the valve within the 120 days? Does "the 120-day clock start" when you notice the failure or when you retrieve the component? For example, for subsea wells, may not be able to retrieve the SSSV that quickly.
Answer	Final § 250.803(b) provides that "[y]ou must ensure that an investigation and a failure analysis are performed within 120 days of the failure to determine the cause of the failure." Accordingly, the 120-day clock begins to run from the date of the failure. BSEE doubled the time originally proposed in order to accommodate commenters' concerns that the proposed 60-day period was insufficient. If you need additional time beyond 120 days to perform the necessary operations, you may request a departure from BSEE.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.805(a) – H_2S and waterflooding
Question	If the reservoir is to be waterflooded, and as a consequence may become sour, does this paragraph apply?
Answer	You are required to follow § 250.490 when operating in H2S areas. § 250.874(e) requires consideration of the effects of H_2S in the design of your waterflood system. If a reservoir becomes sour for any reason including waterflooding, you must adhere to the requirements of § 250.490(d).

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic

§ 250.820 – Leakage rates

Question

Section 250.820 requires surface tree valves (SSVs) to be tested in accordance with API RP 14H which allows a 400 cc/min liquid leakage rate. Section 250.834 requires subsea tree valves (USVs) be tested in accordance with API RP 14H which has the same criteria for USVs as for SSVs. The tables in § 250.880(c)(4) provide the same leakage criteria as API RP 14H for USVs but § 250.880(c)(2)(iv) specifies "If an SSV does not operate properly or if any gas and/or liquid fluid flow is observed during the leakage test, the valve must be immediately repaired or replaced."

There appears to be a conflict between the provisions in the table and the provisions in API RP 14H. Please clarify that the API RP 14H allowable leakage rate applies for the pressure controlling aspect of the valve but "no leakage" applies for only the pressure containing aspect of the SSV as described in API RP 14H?

Answer

In accordance with § 250.800(d), when there is a conflict between the regulations and a referenced document, the regulations control over the referenced document. During monthly testing of SSVs, no leakage is allowed. The same is true for BSDVs. "Under final § 250.880(c)(2)(iv), operators must test SSVs monthly and if any gas and/or liquid fluid flow is observed during the leakage test, the operator must immediately repair or replace the valve. API RP 14H allows for some leakage during this test, however, in the final rule, BSEE requires no gas and/or liquid flow during the leakage test. As previously stated, when there is a difference between the regulations and the incorporated standards, the operator must follow BSEE's regulations." 81 FR at 61866.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.825(b) – Valve and sensor testing
Question	Does § 250.825(b) apply only to SSSVs and sensors related to the SSSVs, and not more broadly to all valves and sensors on a subsea tree?
Answer	All valves and sensors associated with the tree must be tested before the rig or installation vessel leaves the area. Section 250.825(b) does not only apply to SSSVs.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.826 – DWOP requirements
Question	The SCSSV needs to meet the requirements of §§ 250.801 to 250.803 and any DWOP. In the event of a conflict of regulations and DWOP, which takes precedence?
Answer	The regulations are the governing requirement, unless an alternate compliance or departure is/was requested and granted in your approved DWOP, or the DWOP approval contains a condition of approval with a more stringent requirement.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.828(b) – Definition of inoperable
Question	What is the definition of inoperable in this section?
Answer	The SSSV is considered inoperable if it is unable to perform its designed function or unable to meet the closing times and leakage rate requirements of the regulations in § 250.880.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.835(b) – Actuator failure
Question	The regulation states the BSDV must be fire rated for 30 minutes Does this include the actuator or if the actuator fails to a safe position is that adequate?
Answer	If the actuator fails to a safe position, that is adequate.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.835(c) – BSDV location
Question	How would this paragraph be interpreted if a platform's horizontal BSDVs are within 10' of penetration but not on edge of platform?
Answer	If the proposed BSDV location does not meet the required distance specified by regulation, the company may request an alternate compliance under § 250.141 to be evaluated on a case-by-case basis, we recommend early in the design process.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.841(a) – Safety analysis checklist
Question	This statement gives the latitude to use the Safety Analysis Checklists to not install certain equipment; however the rule has included several direct extracts from 14C as requirements with no corresponding ability to meet thru alternate means as the Safety Analysis Checklists. Examples include § 250.858 where the PSH, PSL, LSH and TSH are identified specifically without regard to the compressor type or material selected. This defaults you to an instrumented protection system rather than an inherently safe design. Can you utilize the options provided in API RP 14C (as incorporated by reference) for the development of the Safety Analysis Checklists?
Answer	Section 250.858 requires the identified equipment only "as required in API RP 14C, sections A.4 and A.8…" Operators may utilize all options allowed by API RP 14C, including the Safety Analysis Checklists to develop their safety flow diagrams and SAFE charts.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.841(b) – Temporary repairs
Question	In the past, platforms have been approved for temporary repairs (clamps) for periods of several years. What types of temporary repairs will be allowed under the new rule? Also, please differentiate between temporary repairs for integrity issues that have leaked already vs. temporary repairs used for preventative measures.
Answer	BSEE considers pressures, type of systems, and other factors in considering requests for approval of temporary repairs to piping. It has been the policy of this agency for several years to allow temporary repairs on low pressure process piping. These temporary repairs were approved with the condition that a permanent repair would be complete within 30 days. Based on BSEE's experience, this is typically enough time to make permanent repairs. Final § 250.841(b) is consistent with this existing practice. If an operator faces issues with achieving compliance, it make seek alternate compliance or a departure under the regulations. The rule does not differentiate between categories of temporary repairs to facility piping.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.842(a) – Connections or tie-ins
Question	On a modification to a facility, are you allowed to make connections with (locked closed valves with skillets installed) prior to BSEE approving the modification submittal? The regulations don't say anything about tie-ins or connections. The regulations do make it clear in § 250.842 that before you install or modify a production safety system, you must submit a production safety system application to the District Manager for approval. The regulations also could be read to suggest that you may conduct the installation prior to receiving BSEE approval, but under § 250.800 you must not commence production until BSEE approves your production safety system application and you have requested a preproduction inspection. § 250.869 When pressure or atmospheric vessels are isolated from production facilities (e.g. inlet valve locked closed or inlet blind-flanged) and are to remain isolated for an extended period of time, safety device testing in accordance with API RP 14C is not required with the exception of the PSV .
Answer	You are not allowed to make connections or install equipment prior to BSEE approval.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.842(a) – PE stamp
Question	Do P&IDs held for non-API RP 14C changes and submitted at the end of the year require a PE stamp on each cloud?
Answer	All modifications must be stamped by a registered professional engineer.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.842(a)(3) – Electrical one-line diagrams
Question	How will electrical one-lines be addressed? Similar to minor, non API RP 14C drawings with an annual update? What would be considered "major" such that an approval is required? Are there any major changes that need to be submitted for approval?
Answer	For electrical drawings, any changes to the electrical one-line diagram will trigger a submission

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.842(a) – Electrical and fire and gas systems submitted information
Question	Which documents need to be submitted to meet § 250.842(a)(3) Electrical System Information and § 250.842(a)(4) Schematics of the fire and gas-detection systems? Please provide example list.
Answer	Many of these requirements are substantively unchanged from the requirements previously located at § 250.802(e), with which operators have already been complying. For § 250.842(a)(3) the information may include, but is not limited to: Area classification drawings, One-Line diagrams, and Equipment layouts (with ignition source locations). For § 250.842(a)(4) the schematics may include, but is not limited to: 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.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.842(a)
Question	Do the Fire & Gas loop drawings need to be submitted with the other F&G drawings as other drawings include similar information.
Answer	Please clarify question

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.842(a)(3) – Identification of potential ignition sources
Question	What does BSEE mean with "Identification of all areas where potential ignition sources are to be installed" in § 250.842(3)(ii). Is this part of (i) "Plan outlining all classified areas" and "one-line drawings"? Or is BSEE looking for a separate list with installed electrical equipment in hazardous areas?
Answer	These could be combined onto the Area Classification drawing.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.842 – Replacement in kind
Question	Does replacement in kind need to be submitted for approval?
Answer	Replacement in kind should be discussed with the appropriate district manager.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.842(b), (c), and (d) – Definition of "you"
Question	Does "you" mean the operator must certify or can the operator use a 3rd party contractor to certify?
Answer	The lessee or designated operator must certify.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.842(c) – Certification example
Question	For preproduction certification, what minimum information needs to provided here? Is this just as simple as "I, Joe Smith, certify that xyz was installed in accordance with BSEE approved design"?
Answer	Yes, the example is acceptable, provided it is clear that the signatory is certifying on behalf of the lessee or designated operator. That is, the certification signatory is not certifying in the signatory's individual capacity, but rather on behalf of the lessee or designated operator.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.842 – BSEE response to certification
Question	Do we need to wait for any form of BSEE acknowledgement that this certification was received by them before we can start production?
Answer	You do not need to wait for BSEE acknowledgement to start production unless explicitly stated during the approval process provided you adhere to the conditions of 205.842(c).

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.842(c), (d), and (e) – Timing of submittals to BSEE
Question	Does the installation certification need to be submitted with the as-built submittal.
Answer	No, you have 60 days after production commences to certify the as-built drawings. The installation certification statement required in § 250.842(c) is required before production commences.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.842 – P.E. stamps
Question	Does BSEE accept modified documents with a PE stamp only covering the latest change, i.e. no PE stamp for original drawing?
Answer	Yes, modifications only require the clouded areas to be stamped by a registered P.E.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.842 – P.E. stamps
Question	Do test spread design drawings need to be stamped by PE? Test spread is typically third party rental kit
Answer	Production test package drawings should be stamped by a registered P.E. This P.E. stamp does not need to be from an independent 3rd party. Additionally, the connections of the production test package to the existing system should also be stamped by a registered P.E. (It does not have to be the same P.E.)

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.842 – P.E. stamps
Question	Will BSEE accept drawings (P&IDs) without a P.E. stamp for as-built documents, when the original submittal to BSEE was before the compliance date?
Answer	If BSEE approved production safety system application drawings before November 7, 2016, those approvals will remain effective unless the regulations require the submission of an updated drawing (e.g., upon modification of a production safety system under 842(a)). The as-built diagram certifications under § 250.842(d) apply only to "new or modified production safety systems…." .

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.842 – P.E. stamps
Question	Will BSEE accept drawings without a P.E. stamp that were engineered and finalized (Issued-for-Construction) before the compliance date, but submitted to BSEE after the compliance date?
Answer	BSEE will only accept drawings without a P.E. stamp if they were submitted to BSEE prior to 11/7/16. .

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.842 – Changes that require a P.E. stamp
Question	What size/kind of changes need a P.E. stamp? Only the ones requiring a HAZOP? And what size/kind of changes need to be submitted to BSEE?
Answer	Any changes that require modifications to the SAFE chart or Safety flow diagram per API RP 14C would require a submission to BSEE with a P.E. stamp for those changes.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.842 – P.E. stamps for other documents
Question	Does BSEE expect P.E. stamps on any drawings other than the ones explicitly called out in § 250.842: P&ID, Safety Analysis Flow Diagram, Safety Analysis Function Chart, plan outlining all classified areas, one-line electrical drawings, and schematics of fire and gas-detection systems?
Answer	For this section, P.E. stamps are required only on the drawings identified in § 250.842(a) and their corresponding as-built diagrams.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic

§ 250.842(b) – Definition of electrical system

Question

What is the extent of the meaning of electrical systems? To what level of detail is the Electrical System to be stamped? Does this include the reports and each individual single line, cable tray drawings etc.

Answer

Electrical systems subject to this subpart are defined in § 250.842(a)(3). All plans, drawings, diagrams, etc. of the systems defined by § 250.842(a)(3) or clouded modifications to these documents must be stamped by a registered P.E.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.842 – When to use a P.E. stamp
Question	What is meant by "mechanical systems" and to what level of detail must the mechanical design be stamped? Is this the base process design and PFDs and P&IDs or again do we go into the details of the design such as the PSV-sizing basis, design calculations and vendor supplied actual device rating calculations? What about ASME vessel, these can be purchased worldwide to ASME code? Designs for these vessels generally do not have a P.E. stamp. It is a subset of the base design.
Answer	Only drawingsrequired by § 250.842(a) are required to be stamped under § 250.842(b)(2). Generally, this subpart does not require stamps of individual components of the mechanical systems. However there may be PE stamping requirements outside of this subpart.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.851
Question	The BSEE rule and ASME PV code are not consistent. The ASME code has additional exclusions from code stamping beyond that mentioned in BSEE requirements, thus a vessel that is exempt from ASME Section VIII, by the CFR would still need to be code stamped. For all future pressure vessel procurement, BP would have to require all pressure vessels to be designed and constructed to ASME pressure vessel code. What would be acceptable justification for operation of uncoded equipment beyond March 1, 2018?
Answer	PLEASE CLARIFY

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.851 – Maintenance of boiler and pressure vessels
Question	ANSI/ASME Boiler and Presser Vessel Code, Section I is incorporated by reference in § 250.851 and 250.1629(b). Section 250.851(a)(3) states pressure relief valves must be designed and installed according to applicable provisions in ASME Boiler and Pressure Vessel Code. The word "maintained" has been removed from the predecessor to § 250.851(a)(3). What is the requirement for maintenance? The boiler and pressure vessel code only requires testing and does not mention PSV maintenance requirements.
Answer	The ANSI/ASME Boiler and Presser Vessel Code, Section I does not specifically address maintenance. The relief valve is part of the pressure or fired vessel, so you must repair, maintain, and inspect it as part of the overall vessel according to API 510, as required in § 250.851(a)(1)(ii).

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.851 – PSV testing requirements
Question	Please clarify which PSVs fall under the annual testing requirement. Is the annual testing limited to only those PSVs that fall under API RP 14C requirements? Some PSVs fall under USCG jurisdiction are tested under USCG requirements. However, there are some PSVs on facilities that do not fall in either category.
Answer	Only PSVs that fall under API RP 14C fall under the annual testing requirements.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.851
Question	Subpart H does not contain any requirement for overhauling of PSVs. API RP 570 defines a RBI test interval for pressure relief devices. However API RP 570 is not incorporated by reference in any documentation related to pressure relief valve maintenance. *Suggestion:* Incorporate by reference API RP 570 into §§ 250.851(a)(3) and 250.1639(b)(i) for pressure relieve maintenance. API RP 570 requires relief valves in hydrocarbon services must be overhauled every 5 years and relief valves in non-hydrocarbon service must be overhauled every 10 years
Answer	BSEE will not consider operators' satisfaction of API- or manufacturer-suggested practices for testing PSVs to be sufficient for compliance with Subpart H. Previously, BSEE had allowed operators to just test the pilot of pilot-operated PSVs. This is not allowed under the new regulations, which require that the main valve piston must lift during testing. BSEE will consider granting alternate compliance requests and/or departures (extensions) for the required PSV testing (Lift Main Valve). If BSEE grants an alternate compliance request and/or departure (extension) from the requirement for the main valve piston to lift, the operator is still expected to test the pilot portion annually.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic

§ 250.851(a)(3)(ii) – Documents not incorporated by reference

Question

Section 250.851(a)(3)(ii) states that pressure relief valves must conform to the valve sizing and pressure-relieving requirements specified in applicable provisions of the ASME Boiler and Pressure Vessel Code incorporated by reference. However the ASME Boiler code references other documents such as API 520/521 which are not incorporated by reference. API RP 520 and API RP 521 are also referenced in Table 1 of API RP 14J.

Answer

Although only documents incorporated by reference are regulatory requirements, at times compliance with these documents calls for satisfaction of other requirements. For example, elements that are essential to the incorporated document should be adhered to in order to be in compliance with the regulation

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic

§ 250.852(c) – Flare scrubber sizing

Question

Section 250.852(c)(1) states that (absent equipment that satisfies § 250.852(c)(2)) you must design the flare scrubber to handle, without liquid hydrocarbon carryover to the flare, the maximum anticipated flow of hydrocarbon that may be relieved to the vessel. There needs to be a time element associated with this requirement otherwise the flare scrubber will be large and impractical. Is this requirement of flare scrubber sizing limited to the case of only when the well flow directly to a pipeline without separation on the topsides?

Suggestion:

Specify that the flare scrubber must have the capacity to contain the maximum anticipated flow of hydrocarbon for 45 second duration from the time the high-level trip in the flare scrubber is activated. The 45 seconds is based on the BSDV closure time.

Answer

Section 250.852(c)(1) does not contemplate a limitation on the duration of hydrocarbon flow that the flare scrubber must be designed to meet in the identified circumstances. Flare scrubbers should be designed for continuous flow.

Alternatively, you may meet the requirements of § 250.852(c)(2) to avoid the flare scrubber requirements of § 250.852(c)(1).

Section 250.852(c) only applies where a well flows directly to a pipeline before separation.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic

§ 250.855(b) – ESD schematics

Question

The rule requires that a schematic of the ESD, indicating the control functions of all safety devices for the platforms, must be kept on the platform, at the field office nearest the OCS facility, or at another location conveniently available to the District Manager for the life of the facility.

Is BSEE asking for a new document or will the existing SAFE chart suffice as they have much the same information? Additionally a lot of this info is duplicated on P&IDs and Cause and Effects.

Answer

No, BSEE is not asking for a new document. This is not a new regulation (see former § 250.803(b)(4)(iii)); operators can continue to comply with this requirement as they have previously. The required ESD schematic can be included in your P&ID and safe charts (or cause and effect diagram). It is not required to be a separate and unique document.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.872(b) – Pressure vessels
Question	Are pressure vessels operating at atmospheric treated the same way as an atmospheric vessel?
Answer	API 14C states that vessels operating at < 5psi are considered to be in atmospheric service. Therefore this rule would apply in that case.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.874(g) – Water injection testing
Question	Do the water injection testing requirements only apply to WI systems after the effective date of the rule or do they apply to existing systems as well.
Answer	This is a testing requirement. Operators must follow this for all water injection valves, regardless of when they were installed.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.876 – Fired type heaters
Question	Section 250.876 states that the “fire tube for tube-type heaters that are equipped with either automatically controlled natural or forced draft burners” must be inspected and repaired every 5 years. The title and the content are inconsistent. Based on the text content, are we to conclude this applies only to fired type heaters and thus exclude waste heat exhaust heaters on power turbines?
Answer	That is correct. This regulation applies to fired type heaters and excludes waste heat exhaust heaters.

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.880(c)(4)(iv) – ESD logic
Question	Please clarify what is required to test the ESD logic.
Answer	Pursuant to § 250.880(c)(4)(iv), "Tested at least once each calendar month, not to exceed 6 weeks between tests – BSEE expects all Electronic ESD stations to be tested by verifying the individual ESD station signal reaches the control system(logic solver).

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	§ 250.880(c)(2)(i) – PSV testing
Question	Please clarify what types of alternate compliance methods for this requirement may be acceptable. Many offshore locations are not designed to test in this manner. Design philosophies adopted over many years disallowed the installation of block valves under PSVs to eliminate the possibility of inadvertent shutting of block valves rendering PSVs out of service. BSEE/MMS over many years seemed to promote this philosophy.
Answer	There are various ways to test the PSVs and have the piston lift. If you are unable to test the PSV in a way that verifies functionality of the piston, alternate compliance requests may be considered. However, at this time BSEE does not have a basis for assessing what may be approved..

Subpart H Forum – BSEE Q and A

OOC Submitted Questions

Topic	PINC No. P-451 procedure 7
Question	Please clarify that this should only apply to PSV's installed on ASME stamped vessels. Some PSV's that fall under API 14C are protecting atmospheric vessels or process piping and these do not require PSV's that are ASME stamped.
Answer	Relief valves on atmospheric vessels do not require the ASME stamp. Relief valves on process piping must be marked with an ASME stamp. API 14E requires that systems be designed in accordance with ASME 31.3.

Subpart H Forum

Atmospheric Vessels

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

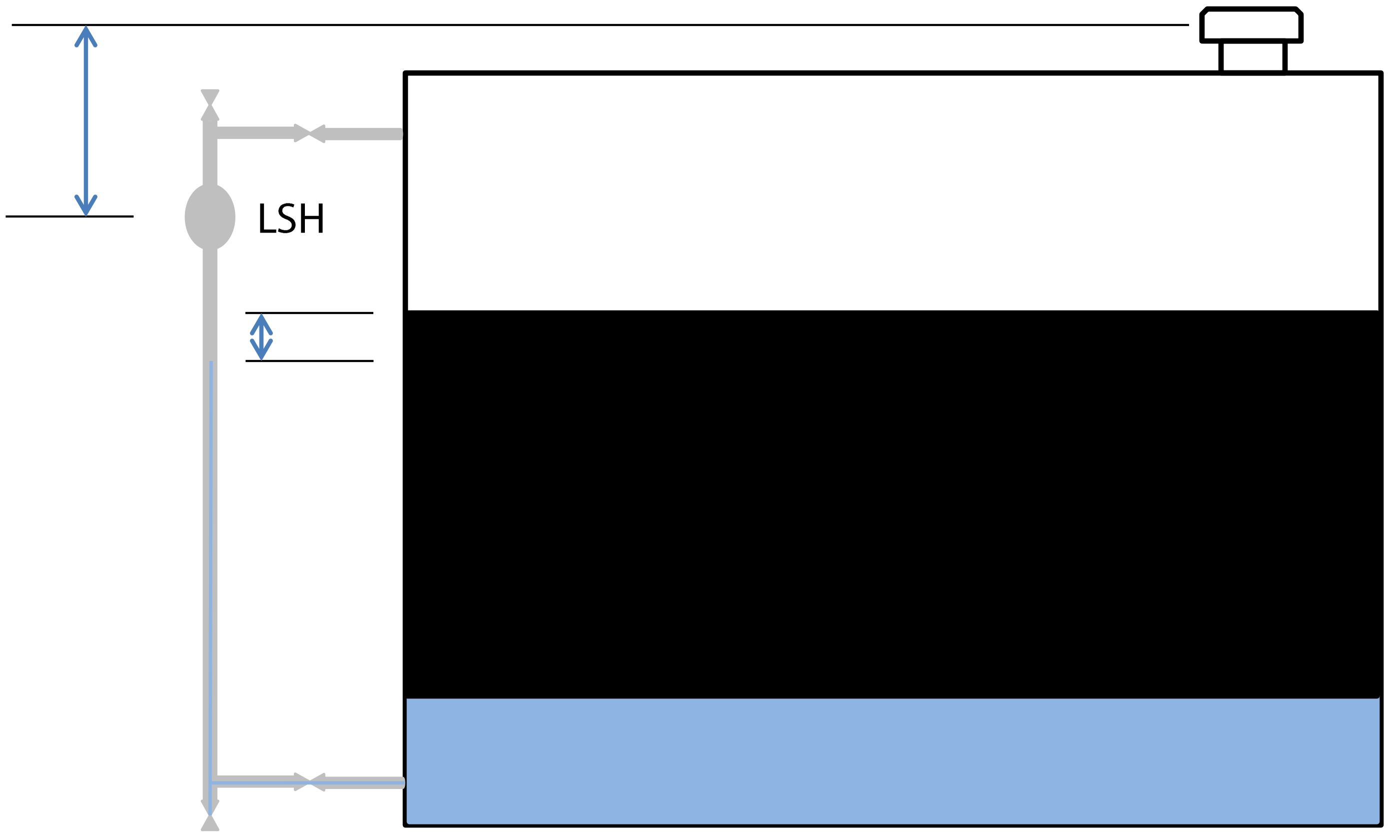
The LSH sensor must be installed to sense the level in the oil bucket.

X **The level sensor must be installed in the oil bucket.**

✓ **The level sensor may be installed in the oil bucket.**

Subpart H Forum

Atmospheric Vessels – No Oil Bucket

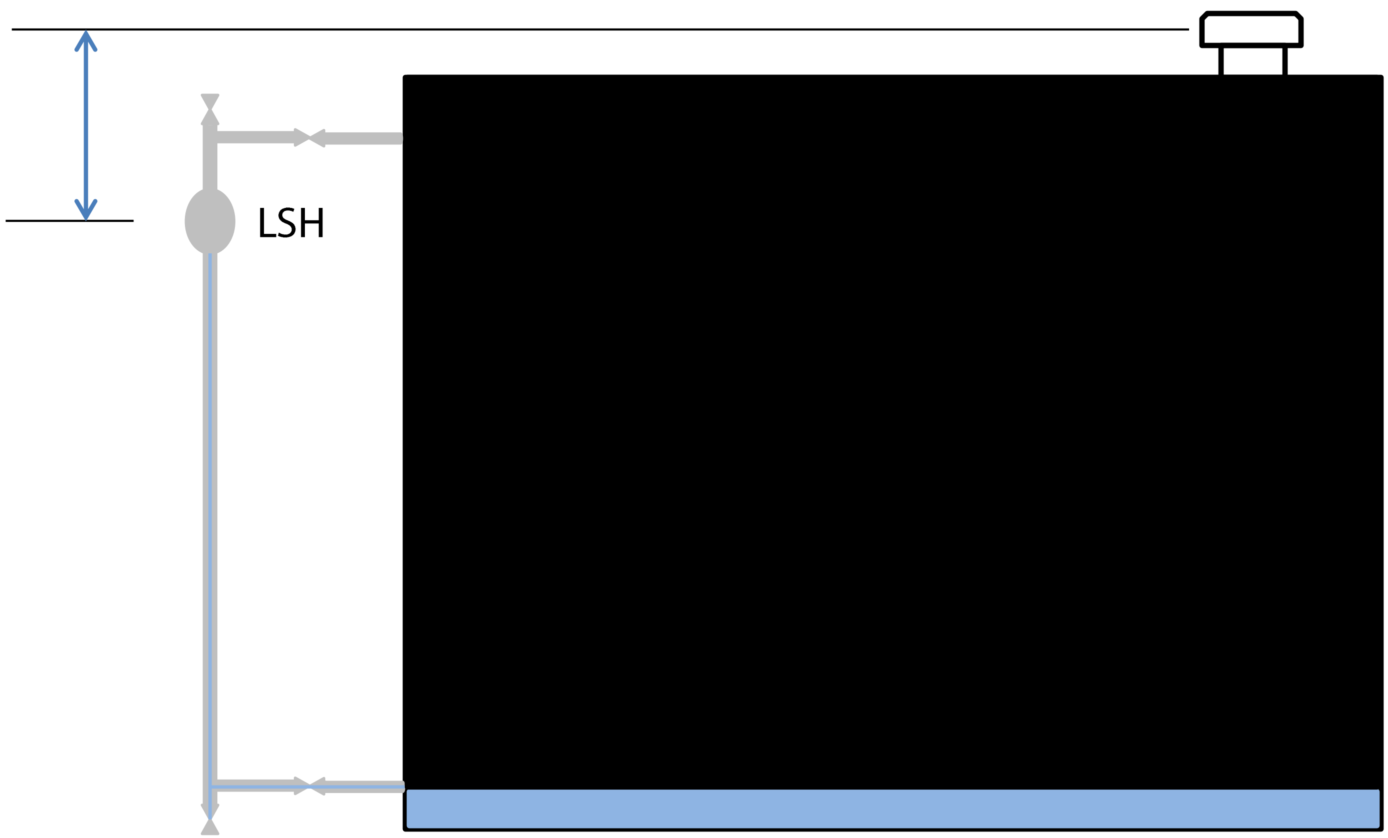


If water level in tank is not monitored and maintained, water can enter the bridle. Density Difference of oil and water can result in overflow without the bridle level reaching the LSH trip point

Subpart H Forum

Atmospheric Vessels – No Oil Bucket

Worse Case Scenario: Vessel is filled with oil and bridle is filled with water



Overflow more likely in Bad Oil tanks that do not have an overflow to good oil tank.

Subpart H Forum

Atmospheric Vessels – No Oil Bucket

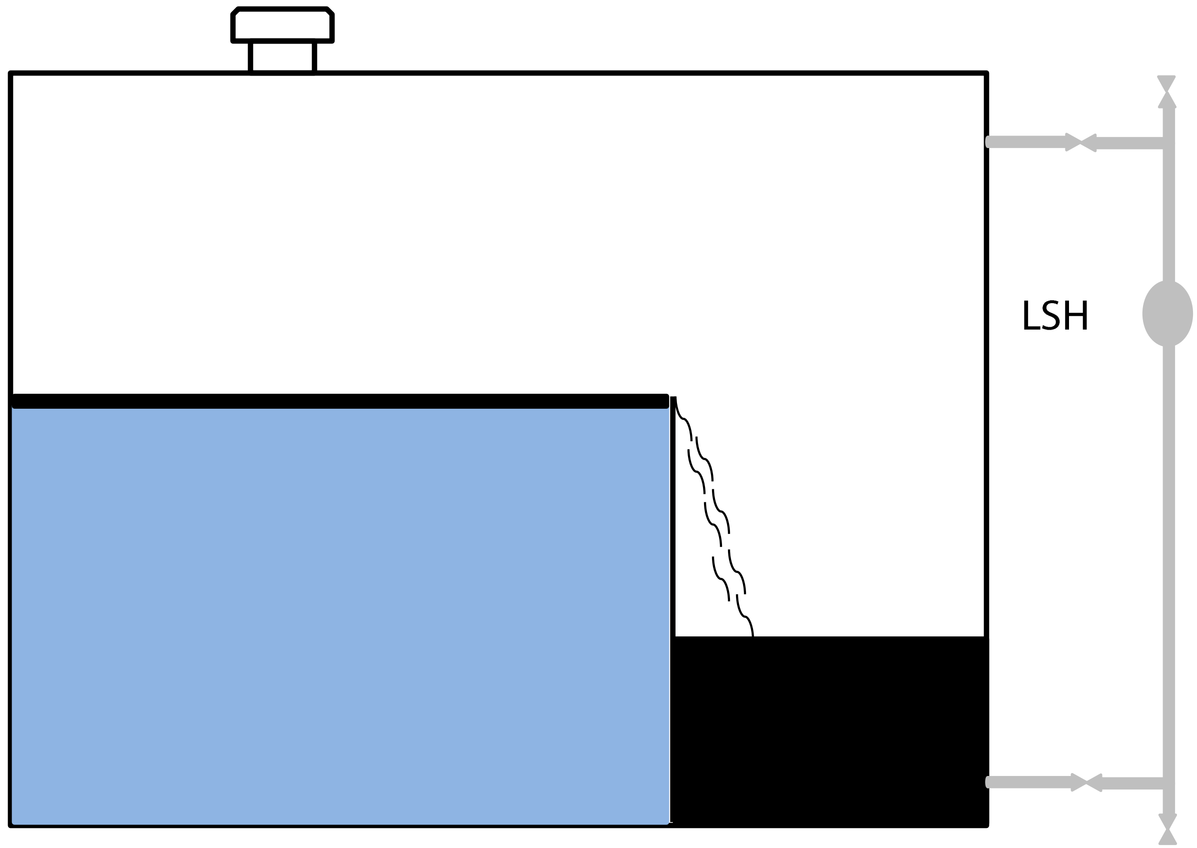
Worse Case Scenario: Vessel is filled with oil and bridle is filled with water

Overflow more likely in tanks that have the upper bridle enter the top of the tank. Oil is not capable of filling the bridle from the top.

Subpart H Forum

Atmospheric Vessels – With Oil Bucket

Bridle installed in oil bucket

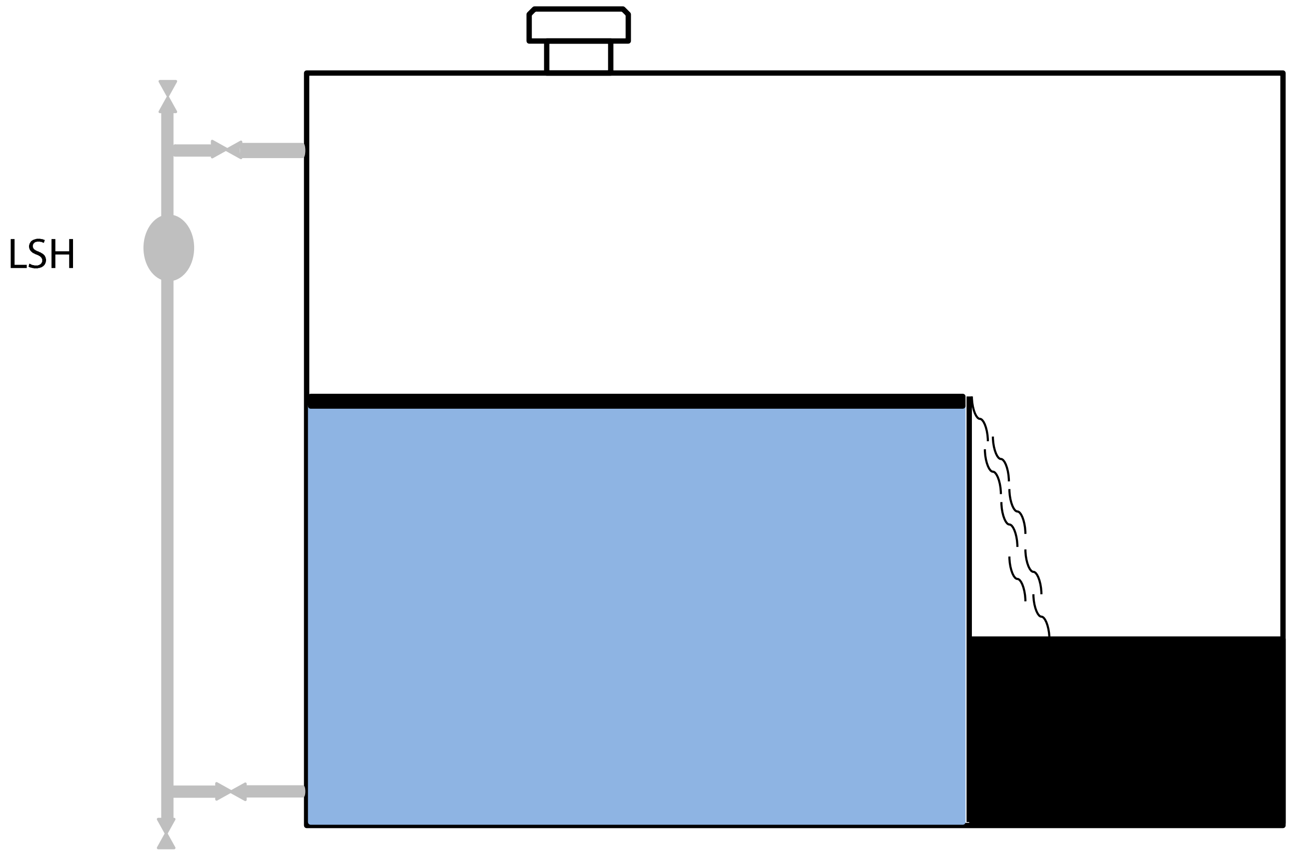


Less likely to have water enter the bottom of bridle.

Subpart H Forum

Atmospheric Vessels – With Oil Bucket

Bridle not installed in oil bucket

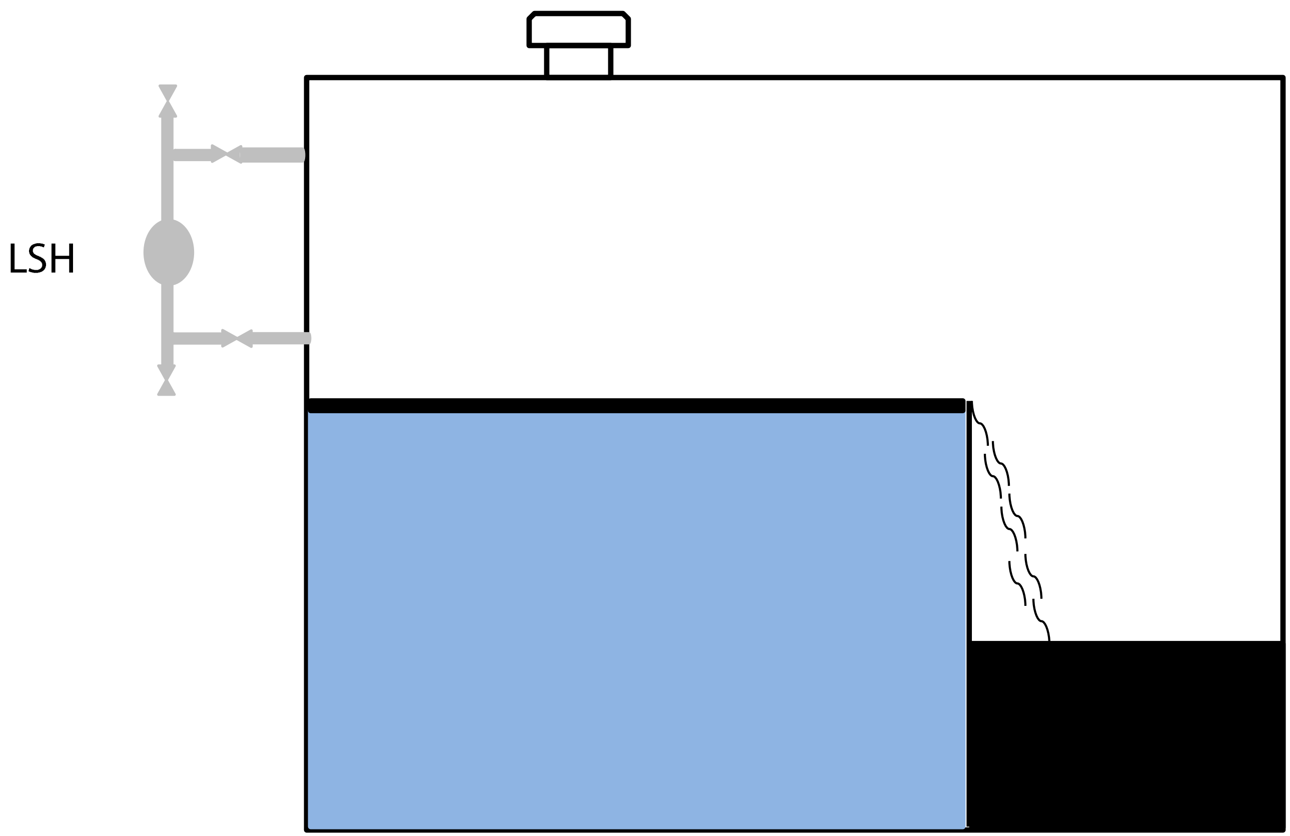


More likely to experience Density Difference issues.

Subpart H Forum

Atmospheric Vessels – With Oil Bucket

Bridle not installed in oil bucket



Not likely to experience Density Difference issues.

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