Oil and Gas Production Safety System Events

2017 Annual Report

U.S. Department of Transportation
Bureau of Transportation Statistics

2017 ANNUAL REPORT

OIL AND GAS PRODUCTION SAFETY SYSTEM EVENTS

U.S. Department of Transportation
Bureau of Transportation Statistics

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EXECUTIVE SUMMARY

The Bureau of Transportation Statistics (BTS), a principal federal statistical agency, entered an interagency agreement with the Bureau of Safety and Environmental Enforcement (BSEE) in 2013, and subsequently signed a Memorandum of Understanding in 2016 to implement and operate the SafeOCS program. The SafeOCS program is a resource for industry members to share key observations and lessons from equipment and safety-related events. Its objective is to identify potential high-consequence risks from aggregated, industry-wide data; and share findings with the industry to mitigate risks. BTS first began collecting data on equipment component failures as required by BSEE's Well Subpart H – Oil and Gas Production Safety Systems Final Rule in December 2016. This report is based on data collected in 2017.

The 2017 annual report: Oil and Gas Production Safety System Failures, produced by the Bureau of Transportation Statistics (BTS), summarizes safety and pollution prevention equipment (SPPE) failures on production well facilities in the Outer Continental Shelf (OCS), with reports received from one region, the Gulf of Mexico, during this reporting period. It includes an analysis of equipment component failures and other key information such as failure causes, operational impacts, and data quality.

SPPEs are valves and actuators designed to stop the flow of oil, gas, and water from wells for safety, pollution prevention, maintenance, or other operational reasons. They will automatically close when triggered by the safety system due to an operation outside of prescribed limits, the presence of gas or fire detected on the platform. Most of the reported failures were detected during required periodic testing, which is performed to find and remove latent failures.

In 2017, the first full year of mandated SPPE reporting, 9 out of 59 production operators in the Gulf of Mexico reported 112 failures. The remaining 50 operators did not report any failures during this reporting period. The 9 reporting operators represent 15 percent of the total operators, 35 percent of active wells, and 40 percent of total oil production from the Gulf of Mexico. None of the reported SPPE events were associated with a Health, Safety, and Environment (HSE) incident. Key findings from the 2017 annual report include:

- ☐ 98 out of 6116 active wells in the Gulf of Mexico in 2017 reported an SPPE failure. The reported failures involved less than 1.0 percent of the SPPE in use on the Gulf of Mexico OCS.
- ☐ Two of the 9 reporting operators accounted for 51 percent of the failure reports, had leases

on less than 20 percent of active wells, and represented less than 5 percent of total oil production from the Gulf of Mexico OCS.

- ☐ All the 112 reported failures except four were located on surface wells. The remaining four which were all BSDVs were on subsea trees.
- ☐ The majority of the SPPE failures (85.7 percent) were categorized as internal leakage, which pose minimal risk—based on the extent of degradation of installed well safety systems and potential consequence to personnel and the environment—than other types of failures such as external leaks and failure to close.
- ☐ SSV failures account for 83 percent of all reported failures. The majority of the SSV failures were internal leakage (88.0 percent) and only 6.5 percent failed to close which posed a higher potential risk but did not lead to an HSE event.
- ☐ Subsurface safety valves (SCSSV, SSCSV) accounted for 13.4 percent of the reported failures.
- ☐ There were 12 failures where the valve failed to close: six SSVs located on the platform, and six subsurface safety valves located away from the platform. One of the failures occurred during a process upset, but it did not lead to an HSE event and the SSV was able to be repaired on location. The remaining 11 failures were found during testing, which helps to ensure that the valve will function if it is needed.
- ☐ Of the 8 failure reports indicating the presence of H_2S, all 8 wells were associated with SSV failures.
- ☐ Of the 7 failure reports indicating the presence of CO_2, 5 were associated with SSV failures and 2 with SCSSV failures.
- ☐ Most of the equipment failures (96.4 percent) were detected through leakage testing.
- ☐ The most reported causes of component failures were *wear and tear* (74.1 percent) and *scale buildup* (7.1 percent).
- ☐ Over 80 percent of the failures occurred on wells producing less than 500 BOE/day, with over half of those producing greater than 100 BOE/day. Only about 1.0 percent of the failures were associated with wells producing more than 10,000 BOE/day (high producers).
- ☐ The most common reported failed SPPE component was the gate and seat degradation in SSVs.
- ☐ Sand, scale, and corrosive environment were the most frequently reported naturally occurring well fluid conditions associated with SPPE failures.

INTRODUCTION

This 2017 annual report, produced by the Bureau of Transportation Statistics (BTS) with data submitted to the SafeOCS program by oil industry operators, presents information on specific equipment component failures occurring on production facilities in the Gulf of Mexico. The SafeOCS program is a resource to help industry members capture and share key lessons from significant near misses and other safety events. Its objective is to identify, prevent, and mitigate potential high-consequence risks by measuring and analyzing failure data while protecting the anonymity of the data providers (e.g. operators and manufacturers).

The SafeOCS program started in August 2013 through an Interagency Agreement between BTS and the Department of the Interior's Bureau of Safety and Environmental Enforcement (BSEE). In November 2016, the SafeOCS program was expanded through a memorandum of understanding (MOU) between BSEE and BTS to include reporting of safety and pollution prevention equipment (SPPE) failure reports as mandated by the Oil and Gas Production Safety Final Rule.[1]

BSEE published the Oil and Gas and Sulfur Operations on the Outer Continental Shelf—Oil and Gas Production Safety Systems Final Rule (Production Safety Systems Rule) on September 7, 2016, with an effective date of November 7, 2016.[2] The Rule defines an equipment failure as any condition that prevents the equipment from meeting the functional specification and requires reporting of such failures.[3] More specifically, pursuant to 30 CFR 250.803, operators must:

(1) Provide a written notice of equipment failure to the Chief, Office of Offshore Regulatory Programs, and the manufacturer of such equipment within 30 days after the discovery and identification of the failure.

(2) Ensure that an investigation and a failure analysis are performed within 120 days of the failure to determine the cause of the failure. Further, any results and corrective action are to be documented. If the investigation and analysis are performed by an entity other than the manufacturer, the Chief, Office of Offshore Regulatory Programs and the manufacturer receive a copy of the analysis report.

[1] See 30 CFR 250.803.
[2] Final Rule, 81 Fed. Reg. 61,833 (Sept. 7, 2016).
[3] 30 CFR 250.803(a).

(3) *design of the equipment that failed or changes in operating or repair procedures as a result of a failure, a report of the design change or modified procedures must be submitted in writing to the Chief, Office of Offshore Regulatory Programs within 30 days.*

Per the MOU, all notifications related to equipment failure are submitted to SafeOCS.

Applicable American Petroleum Institute (API) Standards

The BSEE Production Safety Systems Rule adopts several industry standards developed by the American Petroleum Institute (API)—a national trade association that provides advocacy, research and statistics, standards, certification, events, and training—at times in conjunction with the American National Standards Institute (ANSI). These standards include ANSI/API Specifications 6A, 14A, and Q1; API Specification 6AV1; ANSI/API Recommended Practices 14B; and API Recommended Practices 14E, 14F, 14J, and 500 as listed in 30 CFR 250.198. API Standard 570, "Piping Inspection Code: In-Service Inspection, Rating Repair, and Alteration of Piping Systems" is the only new standard incorporated by reference in the Rule.

When specific SPPE does not perform as designed, operators are required to submit SPPE failure reports as mandated by 30 CFR 250.803, which incorporates the reporting practices found in the API Standards and Specifications (see Appendix A).

About the Report

The interagency agreement between BSEE and BTS requires BTS to publish a report on analysis results, modifications made to the data collection process, lessons learned, and emerging trends based on collected data. This report is the first annual report for SafeOCS SPPE and covers the analysis of failure notifications in 2017 as mandated by the Production Safety Systems Rule. Other key information on operational impact, failure causes, and possible data improvement opportunities is also included in this report. The data analyzed includes failure notifications submitted directly to BTS through SafeOCS or provided to BTS by BSEE.

BSEE defines a *failure* as any condition that prevents the equipment from meeting its functional specifications.[4] In this report, the terms *notice*, *notification*, and *event* generally refer to reported

[4] 30 CFR 250.803(a).

equipment failures and are used interchangeably. Appendix B contains a glossary with detailed definitions of common terms.

SAFETY AND POLLUTION PREVENTION EQUIPMENT

In general, SPPE systems protect offshore personnel and the environment. The specific SPPE covered by the Rule protects personnel and the environment by stopping the flow of well fluids (crude oil, natural gas, and water). These SPPE systems consist of specifically designated safety valves and their control systems, which are required by BSEE regulations and rules, industry standards, or company policies. Currently, they include the following types of valves:

- ☐ Surface Safety Valves (SSVs);
- ☐ Boarding Shutdown Valves (BSDVs);
- ☐ Underwater Safety Valves (USVs);
- ☐ Surface Controlled Subsurface Safety Valves (SCSSVs); and
- ☐ Subsurface Controlled Subsurface Safety Valves (SSCSVs).

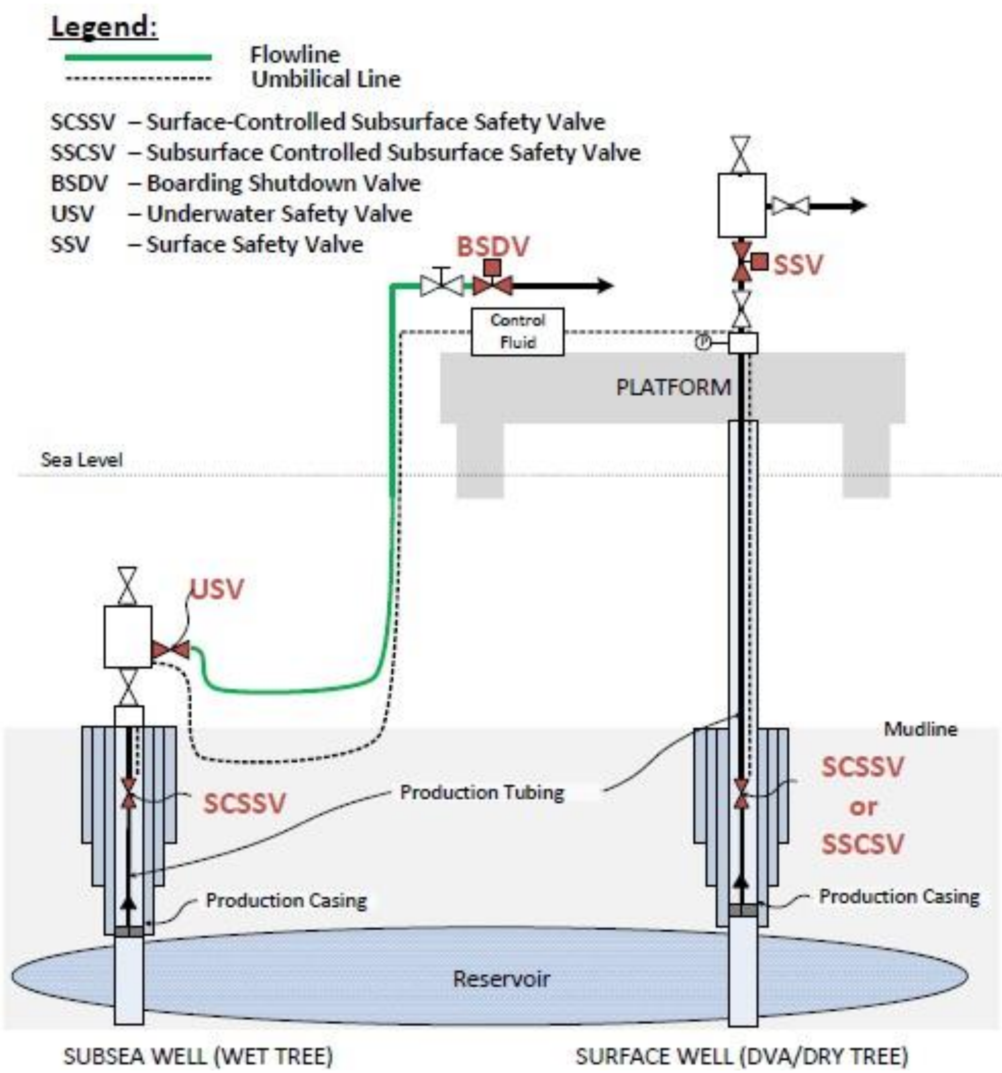
These SPPE valves are found in both surface and subsea wells. Surface wells, which can be production or workover wells, are located above the water line, allowing the operator access to the wellbore from the production platform or platform rig. For a surface well, the wellhead and well tree, called a dry tree, are installed directly on the platform. Subsea wells are located on the seafloor, allowing access to the wellbore only via production flowlines from a permanently installed platform rig, or a mobile or floating rig. For a subsea well, the wellhead and well tree, typically called a wet tree, are installed on the seafloor. Figure 1 illustrates the typical locations of the SPPE valves on each type of well. Some exceptions, however, may be found within certain well trees in the field.

A typical surface well will be equipped with at least one subsurface safety valve (SCSSV or SSCSV, or both) in the tubing below the seafloor or mudline and a surface safety valve on the wellhead. A subsea well, in which the wellhead is subsea, will be equipped with at least one subsurface safety valve and a USV. SSCSVs are no longer allowed in new subsea wells. Per 30 CFR 250.833[5], a production master or wing valve may qualify as a USV under API Spec. 6A and API Spec. 6AV1. In addition, the flowline that

[5] 30 CFR 250.833 – Specification for underwater safety valves (USVs).

transports well fluids from one or more subsea wells will be equipped with a BSDV on the production facility.

Figure 1: Equipment Schematics



SOURCE: U.S. Department of Energy, Office of Science, Argonne National Laboratory, diagram courtesy of funding from U.S. Department of Interior, Bureau of Safety and Environmental Enforcement. (Note: "DVA" refers to direct vertical access.)

SPPE are operated in the open position to allow the production well to flow. All SPPE are considered isolation valves and mechanical barriers because they are designed to stop the process flow. In general, the main valve component moves from an open to a closed position where it contacts the valve seat to seal off the internal flow in the pipe or tubing. Differences in the specific type and make-up of valves, however, can be found among each SPPE valve.

Most SSVs and USVs are sliding gate valves that are hydraulically or pneumatically operated. BSDVs are commonly gate or ball valves. Gate and ball valves are operated either manually or automatically. Manual valves utilize a manually operated handle or hand wheel, and automated valves utilize a hydraulic or pneumatic actuator to open and close the valve.

The SCSSV is a fail-safe closed, flapper-type valve that uses hydraulic control pressure to push down on the piston to overcome the spring force and open the flapper disc to allow flow. SCSSVs are typically full opening valves that allow for wireline work to be accomplished below the valve. The SCSSV is installed in the tubing and can only be retrieved for repairs if the tubing is removed from the well. As an alternative to pulling the tubing to retrieve a failed SCSSV, a wireline retrievable SCSSV can be installed in the wellbore.

The SSCSV is a normally open valve in the well tubing that closes at a predetermined flow rate from the well. The spring force acts downward on the piston which holds the flapper open. At high flow rates, the differential pressure across the valve causes the piston to rise and allow the flapper to close and stop the well flow up the tubing. The SSCSV can be retrieved by wireline for maintenance or other downhole operations as needed.

SPPE are required to be function tested and leak tested per the requirements of 30 CFR 250.880. Additional guidance is provided in BSEE Notice to Lessees (NTL) No. 2009-G36, *Using Alternate Compliance in Safety Systems for Subsea Production Operations*. Table 1 summarizes the testing frequencies and leakage requirements in general. However, exceptions can apply for different types of wells.[6]

Table 1: Typical SPPE Testing Frequency and Leakage Allowance

Valve	Allowable Leakage Rate	Testing Frequency
SSV	Zero Leakage	Monthly, not to exceed 6 weeks
BSDV	Zero Leakage	Monthly, not to exceed 6 weeks
USV	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
SSCSV	N/A	Remove, inspect, and repair or adjust semi-annually, not to exceed 6 calendar months between tests for valves not installed in a landing nipple and 12 months for valves installed in a landing nipple.

[6] Additional information and requirements for new wells and suspended wells are provided in the CFR and the NTL.

Well Production and Well Testing Reporting

The quantity of oil, gas, and water produced from a well is called *well production*. Well production is measured periodically by temporarily segregating a well's fluid stream (from the other wells that might typically flow as a commingled stream) and measuring the fluid rates (oil, gas, and water). Fluid rates are measured using flow meters installed on the oil, gas, and water streams exiting a three-phase separator, typically called a "well test separator." Procedures for well production reporting and well test reporting in the Gulf of Mexico, Pacific, and Alaska OCS regions are codified in BSEE regulations 30 CFR 250 Subparts K and L. Subpart L—Oil and Gas Production Measurement, Surface Commingling, and Security describes the measurement and production well testing requirements. Well tests are based on BSEE procedures[7] which require lessees (i.e., operators) to submit well test reports at least once every six months for each producing completion. Although the well production rate is not a factor in the reported failures, it was used to provide context to the failure's potential impact.

DATA COLLECTION AND VALIDATION

Reporting SPPE Failures

SPPE failures can occur during normal operations, on demand, or when the SPPE is shut-in for its routine function test. Operators must report failures of SPPE systems and their components to BSEE and original equipment manufacturers (OEMs) within 30 days of discovering and identifying a failure. BSEE has directed the industry to submit all notifications to SafeOCS. During the reporting period, operators submitted the notifications in several formats: handwritten forms, Word documents, PDFs, and website forms. In total, this report is based on 112 notifications reported in 2017.

Data Validation

SafeOCS retained subject matter experts (SMEs) in production operations, subsea engineering, equipment testing, well equipment design and manufacturing, root cause failure analysis, quality assurance and quality control, and process design. The SMEs assisted in reviewing notification data for accuracy and consistency and provided input to the analysis.

[7] 30 CFR 250.1151(a)(2).

Data Confidentiality

The confidentiality of all data submitted directly to SafeOCS is protected by the Confidential Information Protection and Statistical Efficiency Act of 2002 (CIPSEA). However, the confidentiality of data submitted directly to BSEE is not protected by CIPSEA. Data protected under CIPSEA may be used only for statistical purposes. This means that only summary statistics and data analysis results will be made available; incident microdata collected by SafeOCS may not be used for regulatory purposes. Information submitted under this statute is protected from release to other government agencies including BSEE, and Freedom of Information Act (FOIA) requests and subpoenas.

DATA ANALYSIS

The BSEE Production Safety Systems Rule covers production operations on the OCS, which includes three BSEE regions (Gulf of Mexico, Pacific, and Alaska). For 2017, SafeOCS received equipment failure notifications for events in the Gulf of Mexico only, which accounts for over 97 percent of offshore production in the United States. Most wells are in the central Gulf of Mexico areas closest to the Louisiana shoreline. Exact locations of reported equipment failures are not disclosed in this document to protect the confidentiality of the data.

SafeOCS received 112 notifications for SPPE failures occurring in 2017. During the reporting period, there were 6,116 active wells[8] and approximately 300 flowlines total in the Gulf of Mexico. The failure rate ranges from 0.6 to 0.9 percent per SPPE, with an overall rate of failure of less than 1.0 percent. The range calculation is based on the assumption that each of the active wells has two to three SPPE valves.[9]

Figure 2 breaks down the 112 notifications by month of failure date. As 2017 is the first year of SPPE reporting, a trend based on reporting month cannot be determined.

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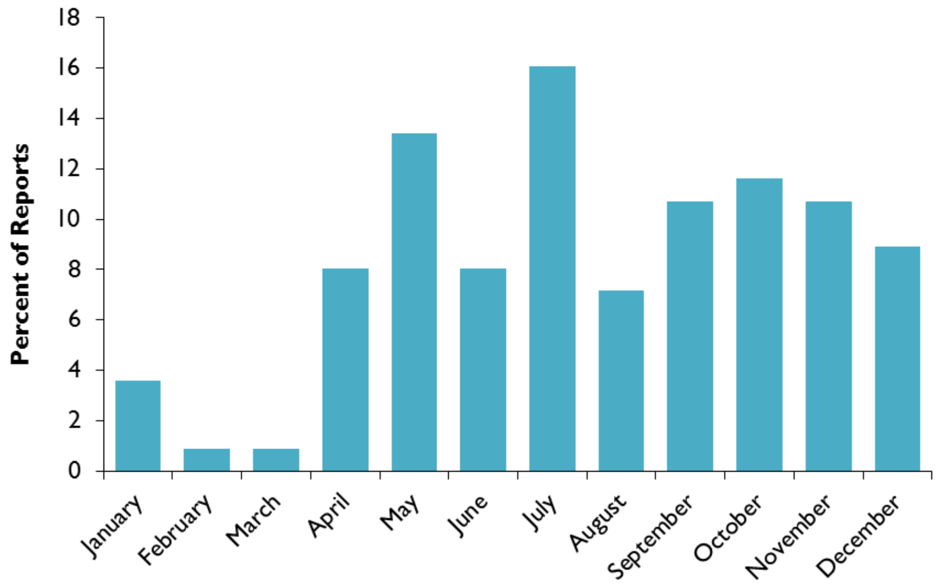
[8] Annual number based on BSEE OGOR-A data.

[9] Range calculation:
Lower limit: 112 / (6116*3) = 0.6
Upper limit: 112 / (6116*3) = 0.9

Figure 2: Percent of Reported Events by Month

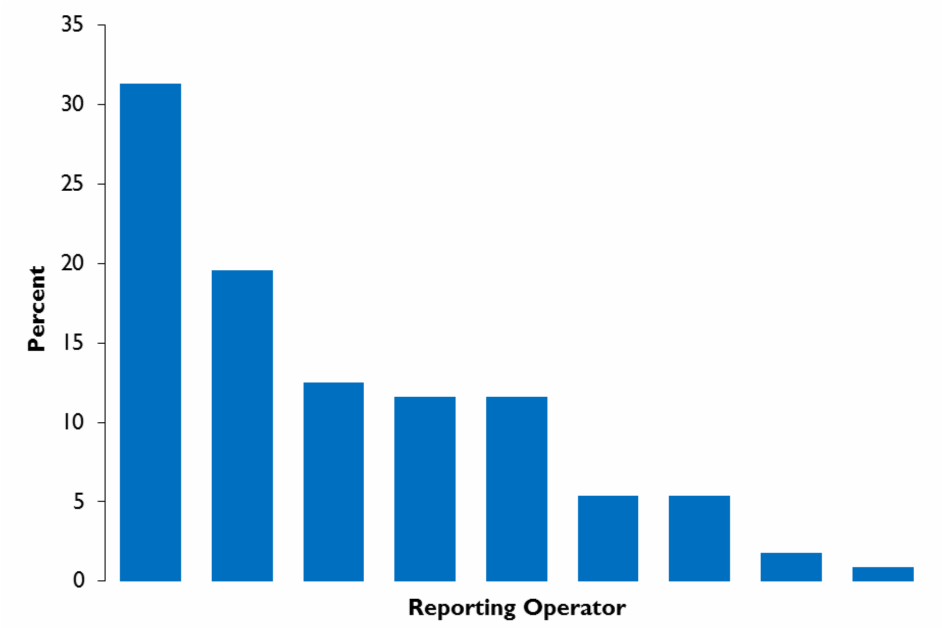


SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

Who Reported Equipment Events

In total, 59 operating companies in the Gulf of Mexico OCS were listed as having active wells in 2017. Based on information received from BSEE, 57 operators had production from the Gulf of Mexico OCS in 2017. An additional two operators were associated with wells with no reported production in 2017, but they are still responsible for testing equipment and maintaining the well. During the reporting period, 9 out of the 59 operators submitted SPPE failure reports (Figure 3). Two of the 9 reporting operators accounted for 51 percent of the failure reports, had leases on less than 20 percent of active wells, and represented less than 5 percent of total oil production from the Gulf of Mexico OCS.

Figure 3: Reporting Activity by Operator

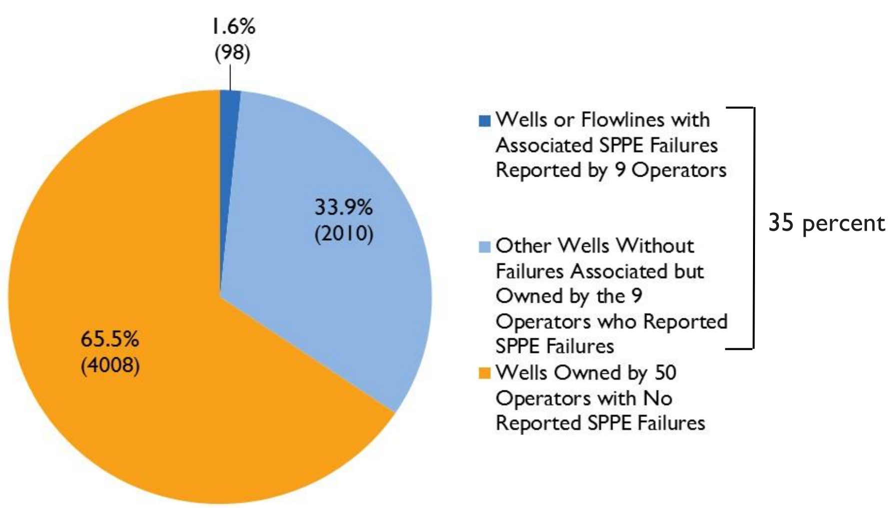


NOTE: Operator names have not been disclosed to preserve reporter confidentiality.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

Figure 4 shows the distribution of active wells between reporting and non-reporting operators.

Of the 6,116 active wells, 98 were associated with a reported SPPE failure. The nine reporting operators represent 15 percent of all operators, hold leases to 35 percent of active wells, and account for 40 percent of oil production from the Gulf of Mexico OCS. The remaining 50 operators with no reported failures hold leases on 65 percent of wells and represent 60 percent of oil production.

Figure 4: Active Wells and Reporting Status by Operator



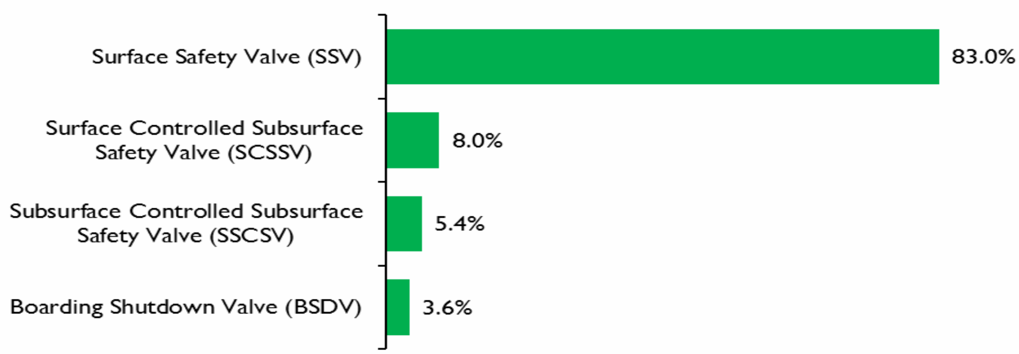
NOTE: Average annual number of wells – 6,116.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

Details of Reported Equipment

As stated above, the SPPE rule covers five main valves in the well or production stream that directly control the flow of hydrocarbons: SSV, SCSSV, SSCSV, BSDV, and USV. The frequency of testing varies across the SPPE valves, as detailed in Table 1, creating the potential for identifying more failures in one type of valve versus another. For example, SCSSVs are tested every six months whereas SSVs are tested monthly, leading to a potential six-fold increase in the opportunity to identify a failure. Like SSVs, BSDVs are also tested monthly.

The percentage of failures from each valve is illustrated in Figure 5. Though both SSVs and BSDVs are tested monthly, the SSV population in the field is greater than that of BSDVs explaining the higher percentage of SSV failures than BSDVs. Furthermore, BSDVs are only found on subsea wells, of which there were only approximately 300 wells out of 6,116 total active wells on the Gulf of Mexico OCS during the reporting year, giving a 1:60 ratio of BSDVs to SSVs, respectively. These differences, in part, explain the higher percentage of SSV failures versus BSDVs shown in Figure 5. All the reported failed valves except four which were located on a dry tree, meaning the tree was on a surface well. The remaining four, which were all BSDVs, were on subsea trees. All but one of the reported SPPE failures, occurred on active production wells.

Figure 5: Reported Events by SPPE Valve Type



SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

Over 86 percent of the failures occurred on SPPE located on the platform (SSVs and BDSVs, see Figure 1 for valve location) rather than in the wellbore tubing or below sea level. This may be partially due to the more frequent testing requirements and more stringent leakage limits for the valves located on the platform. The majority of the SSV failures were internal leakage (88.0 percent), but there were six failures (6.5 percent) where the SSV failed to close. Subsurface safety valve failures accounted for 13.4 percent of the reported failures, with SCSSVs accounting for over half of these. There were no reported USV failures.

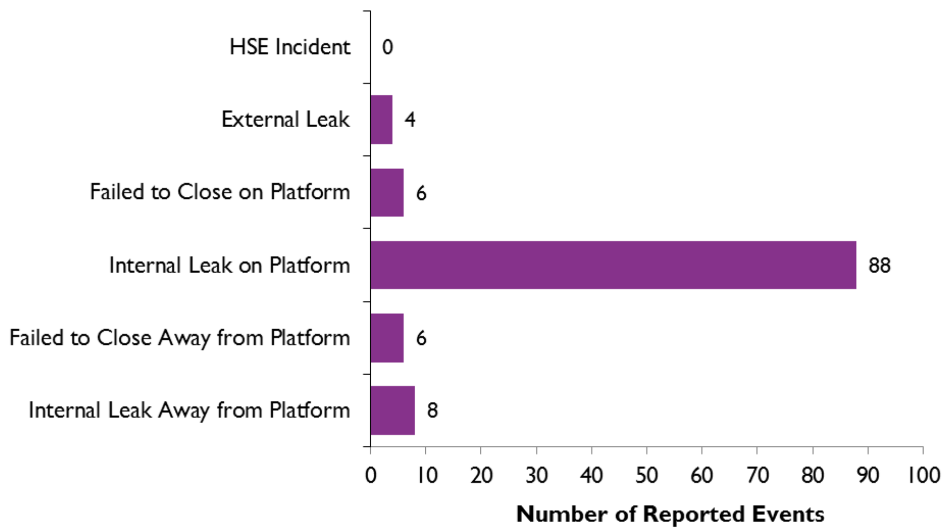
To put SPPE failures in perspective, one must consider the potential consequences of such failures. An assessment was done to categorize SPPE failures based on the extent to which they degrade the installed well safety systems and potential consequence to personnel and the environment. These categories are described below and their frequency is illustrated in Figure 6. None of the reported failures were associated with a Health, Safety, and Environment (HSE) incident (see Appendix E for more information on what constitutes an HSE incident).

- ☐ The type of failure reported with the highest significance is an external leak, where fluids would have the potential to leak into the environment or platform. Four external leaks were reported:
    1. One report of an SSV that leaked during a pre-use test after it had been out of service for several years,
    2. One report of a leak on a temporarily abandoned well.

       Failures 1. and 2. were external leaks from the process flow (i.e., well fluids); however, neither of the associated wells were flowing wells and therefore posed no environmental risk.
    3. Two additional reports of external leaks were from valve actuators, labeled as a small instrument gas leak and a liquid leak.
- ☐ The second most significant type of failure reported was SPPE on the platform failing to close, which means that SPPE would not be effective in controlling the well flow if called upon. Out of the 112 failures, six failed to close and were located on the platform. Alternative SPPE were available in all but one case.
- ☐ The third most significant type of failure reported was SPPE on the platform with internal leakage, which means the valve closed but failed to seal, allowing some fluid to flow through it. These valves are allowed zero leakage, and internal leakage was the most common failure type. Internal leakage events were reported for 88 SPPE valves located on platforms.
- ☐ The fourth most significant type of failure reported was SPPE away from the platform (subsea or in the well) failing to close, which means that SPPE would not be effective in controlling the well flow if called upon. Six such failures were reported.

- ☐ The last level of significance is a failure of SPPE away from the platform (subsea or in the well) with internal leakage. There were eight failures reported for SPPE away from the platform where the internal leakage rate exceeded the allowable leakage rate. In these cases, alternative SPPE were located on the platform.

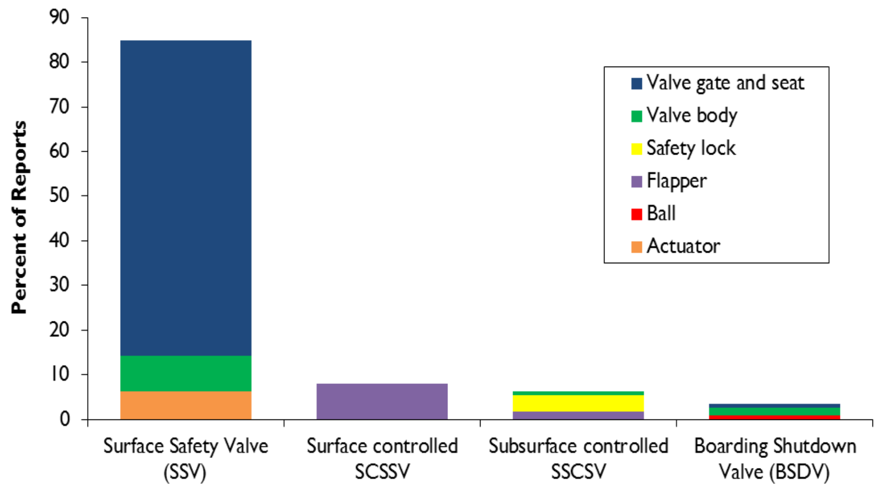
Figure 6: Nature of Reported Event



SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

Multiple components make up each SPPE valve. The table of SPPE valves and their corresponding components can be found in Appendix C. Figure 7 expands upon the reports received, showing the number of components that failed within each valve. A failure of the actuator could prevent the valve from closing when it is called upon, or lead to a leak of the control fluid. Flappers and valve gates and seats are internal components, and their failure to seal would lead to internal leakage.

Figure 7: Components within SPPE Valves in Reported Notifications



SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

Operating Conditions and Well Fluids

Operators are responsible for tracking the well production rates of hydrocarbons (oil and gas) and water for all producing wells on the OCS. This is accomplished by performing monthly well tests to calculate the measured flow. Depending on the well, the well test rate can range from a few barrels of oil equivalents per day (BOE/day) to over 10,000 BOE/day. The significance potential of a failure increases proportionally to the well test rate. Table 2 shows the most recent well test rate operators conducted prior to the failure. Most of the well test rates (80.4 percent) on wells associated with failures were producing less than 500 BOE/day, which are more typical in surface wells, posing a lower significance of risk than higher producing wells.

SPPE valves can be designed for extreme exposure conditions, typically for high pressure (greater than or equal to 15,000 psi) and high temperature (greater than or equal 350˚F) (HPHT). Twenty failure reports (18.0 percent) indicated that the SPPE were designed for HPHT conditions. The design pressure and the upper limit of the design temperature for all SPPE with reported failures are shown in Table 3.

Table 2: Well Test Rates

Well Test Rate (BOE/day)	Percent of Notifications
0-99	42.9
100-499	37.5
500-999	5.4
1,000-4,999	7.1
5,000-9,999	0.0
10,000+	0.9
Not Answered	6.3

Table 3: Design Pressure and Design Temperature of All Reported SPPE

Design Pressure (psi)	Percent of Reports
0 - 4,999	8.9
5,000 - 9,999	52.7
10,000 - 14,999	19.6
15,000+	10.7
Not Answered	8.0

Note: The most common standard pressure design ratings are 5,000, 10,000, 15,000, and 20,000 psi. The most common standard temperature design ratings are 250˚F and 350˚F.

Design Temperature (˚F)	Percent of Reports
0-99	3.6
100-199	3.6
200-299	41.1
300-349	5.4
350-399	3.6
400-499	1.8
Not Answered	40.2

Contaminants

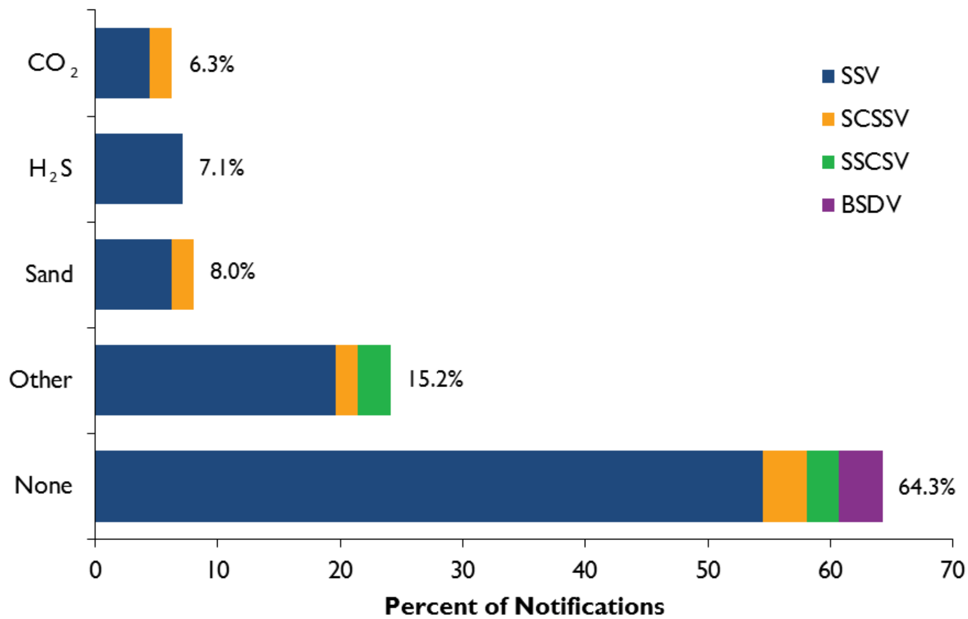
In addition to producing oil, gas, and water, production wells may contain unfavorable contaminants and conditions in the well stream, shown in Figure 8. Certain wells naturally contain hydrogen sulfide (H_2S) or carbon dioxide (CO_2), both of which can lead to corrosion damage to the equipment. Of the failure reports indicating the presence of H_2S, all eight wells were associated with SSV failures. Of the failure reports indicating the presence of CO_2, five were associated with SSV failures and two with SCSSV failures.

Well fluids can also carry formation sand through the valves in the tree during production. The presence of sand can cause mechanical damage by eroding the equipment, and could plug components within the production equipment. The reports indicating sand present in the wells included seven SSV failures and two SCSSV failures.

Even though there were well stream contaminants present, they may not have been the cause of the failure. More information on cause is described in the next section. More than half (64.3 percent) of the reports did not indicate any contaminants, and one well contained multiple contaminants (both sand and CO_2). Those who chose "other" specified the following contaminants:

- ☐ Scale from calcium, salt, and unspecified;
- ☐ Scarring or pitting without a specified cause;
- ☐ A depleted zone;
- ☐ Cement; and
- ☐ Four did not include any additional specifying information.

Figure 8: Well Stream Contaminants



NOTE: Reporting operators have the option to select more than one contaminant.

SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

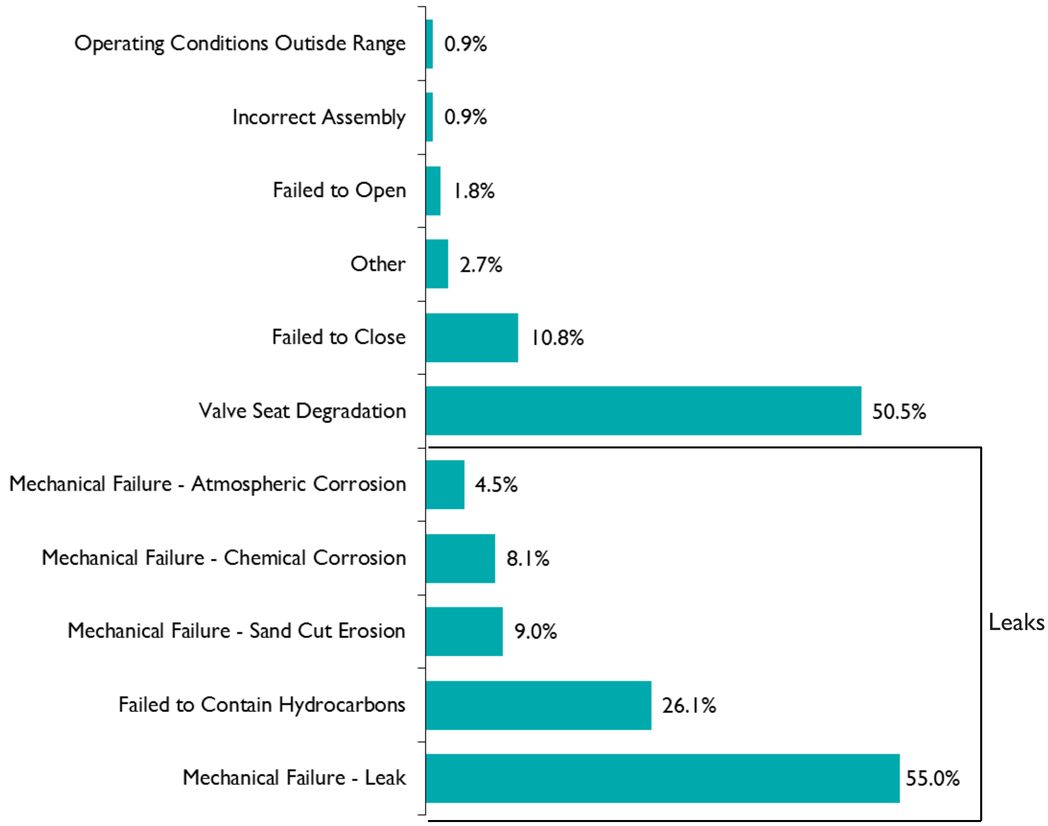
Details of Reported Events

The observed failure was determined by qualitatively analyzing the description of failure narrative. As stated above, most of failures were internal leaks (85.7 percent) which pose minimal risk, and four failures were external leaks (3.6 percent). The other two types of observed failures were the valves failing to close (10.7 percent) and failing to open (1.8 percent). One failure reported the valve both failing to close and failing to open.

Operators were asked to report all contributing factors of the failure, for which the results are shown in Figure 9. The leaks were broken down into the following contributing factors: failed to contain hydrocarbons, mechanical failure – leak, mechanical failure – sand cut erosion, mechanical failure – chemical corrosion, and mechanical failure – atmospheric corrosion. A failure to contain hydrocarbons means that the internal leakage across the valve's sealing component was resolved by a simple service, such as a water wash or greasing the valve. Mechanical failure – leak was designated when the leak required a more robust corrective action, such as repairing a component or replacing the valve. Mechanical failure – sand cut erosion was designated when the SPPE is degraded by sand contaminants.

Chemical corrosion is internal corrosion usually caused by the presence of either H_2S or CO_2, whereas atmospheric corrosion is external corrosion usually caused by moisture or chlorides that affect susceptible metal surfaces. Depending on the metallurgy, the temperature, and the concentration of H_2S or CO_2, corrosion could occur quickly or from prolonged exposure.

Figure 9: Contributing Factors to Equipment Events



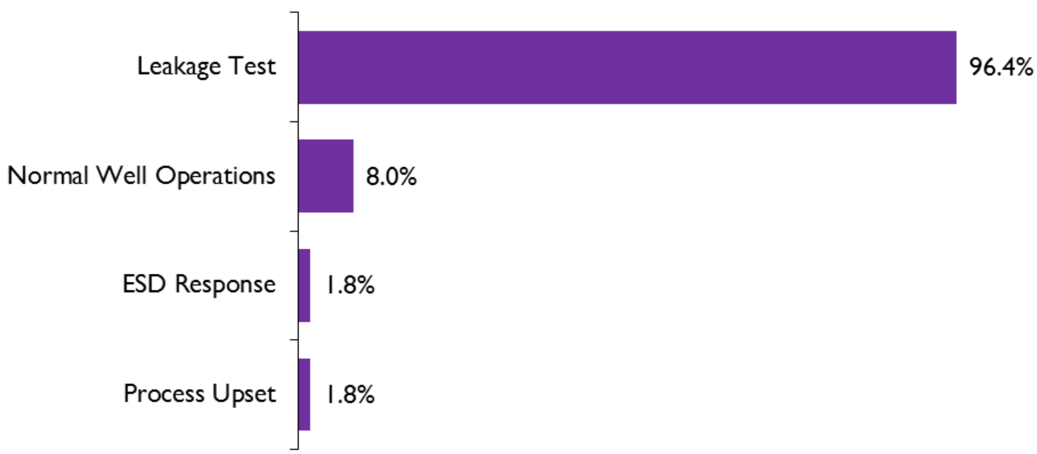
NOTE: Reporters could choose more than one contributing factor.

SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

The failures described above could be detected in a number of ways. For example, they could be found during testing, while the equipment is undergoing normal operation, or when production is required to halt – also called "shut-in" – due to abnormal or emergency conditions. A most (96.4 percent) of failures in 2017 were found during routine leakage tests (see Figure 10). Failures during normal well operations are those that are detected during routine inspections, surveillance, or well closures for other operational reasons. ESD response means that the Emergency Shutdown (ESD) system was manually activated, shutting in all wells. ESD system testing is conducted regularly, with one section tested each month. If an SPPE valve leaks after being closed by the ESD system, it is considered an "ESD response." Similarly, a process upset could trigger an automatic or manual shut-in of the well SPPE. A process upset is when an event, such as a surge in production flow or an adjustment in pressure, causes the pressure to be outside of the safety shutdown set points on the equipment. If an SPPE valve leaks after a process upset causes its closure, the method of detection is the process upset.

When a failure is found, the well must be shut-in until the appropriate corrective actions have been taken to fix the failed component. Failures could also be found when the well is already shut-in (i.e. in shut-in well status) due to operational reasons or integrity concerns. Just under half (47.8 percent) of the failure reports indicated that the well was shut-in when the failure occurred.

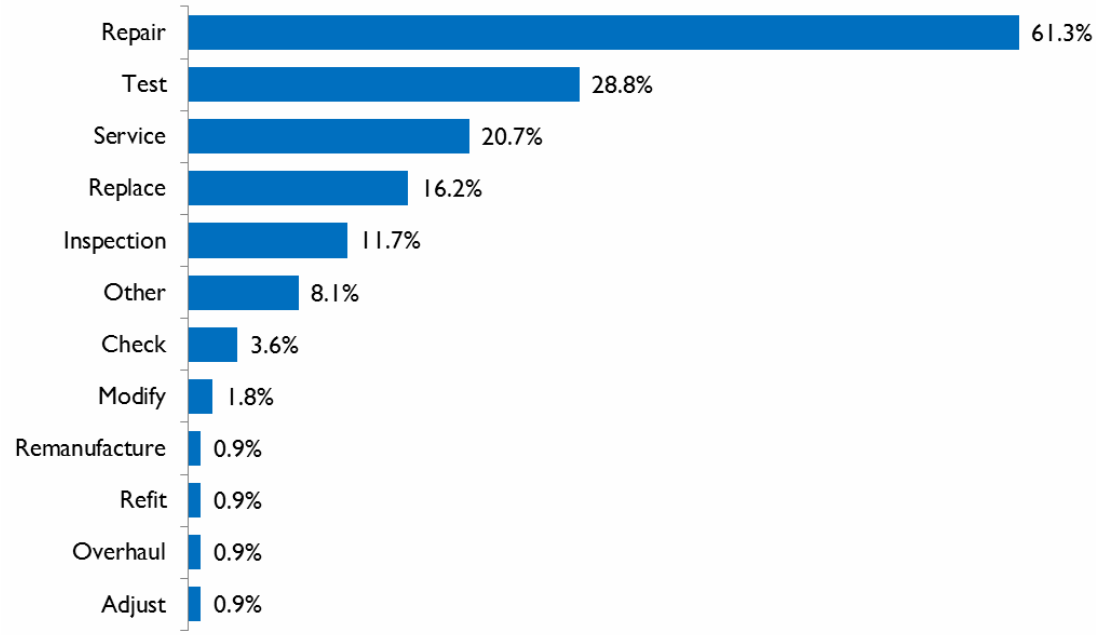
Figure 10: Method of Detection



NOTE: Reporters could choose more than one method of detection.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

Failure reports described corrective actions taken to address the failure (Figure 11). There could be one or more corrective actions per failure, and can range from component servicing to repair or replacement. For example, some reporters described scale buildup on the valve, which may have required only servicing to correct. Other failures required components within the valve or the valve itself to be repaired or replaced. Several reporters chose multiple options to indicate the process taken to address the failure; e.g., testing to locate the failed valve, inspecting the valve to pinpoint the issue, servicing the valve, and/or retesting.

Figure 11: Reported Corrective Actions by Type



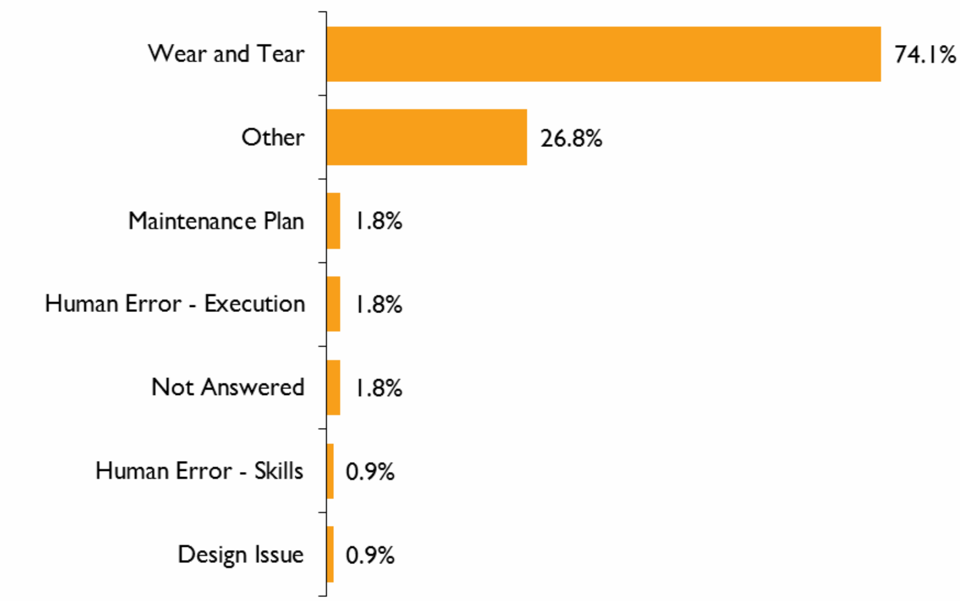
NOTE: Reporters could choose more than one corrective action. The total number of corrective actions chosen by reporting operators was **173**

SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

Operators identify and report the suspected root cause of the failure, illustrated in Figure 12. Wear and tear was the most commonly reported root cause (73.6 percent) with SSVs making up most of those failures (90.4 percent). Wear and tear was reported in almost every failure, including those reporting operation conditions outside of range, sand cut erosion, chemical corrosion, failure to open, and failure to close. There was not enough data regarding the installation date to determine how long the SPPE was in place to further explore what constitutes normal wear and tear.

The second most common root cause was "other," though most reporters did specify a root cause to accompany the choice. Those choosing "other" specified several causes, such as scale build-up, debris, the presence of sand, and corrosion. Within "other," scale build-up accounted for 7.1 percent of reported root causes. Of the 9 wells with sand present, only 2 specified that the presence of sand was the root cause of the failure. Of the 8 wells with H_2S present, 2 specified scale build-up as the root cause.

Figure 12: Reported Root Causes



NOTE: Total number of failure notifications = 112

NOTE: Reporters could choose more than one suspected root cause.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

Results and Conclusions

SPPE failure data can be used to develop an improved understanding of the nature of the failures and the locations and contributing factors leading to the failures, and the nature of the failures. Key observations from the 2017 SPPE failure data include:

- ☐ There were 112 SPPE failures reported to SafeOCS by 9 out of the 59 operators in the Gulf of Mexico. It's important to note that none of the reported failures were characterized as an HSE incident and therefore posed no risk to personnel, the environment, or the safety of production operations.
- ☐ The 9 operators that reported SPPE failures represented 15 percent of all operators, held leases to 35 percent of active wells, and accounted for 40 percent of oil production from the Gulf of Mexico OCS.
- ☐ Two of the 9 reporting operators accounted for 51 percent of the failure reports, had leases on less than 20 percent of active wells, and represented less than 5 percent of total

oil production from the Gulf of Mexico OCS.

- ☐ 98 out of 6116 active wells in the Gulf of Mexico reported an SPPE failure in 2017. The reported failures involved less than 1.0 percent of the SPPE in use on the Gulf of Mexico OCS.
- ☐ All the 112 reported failures except four were located on surface wells. The remaining four which were all BSDVs were on subsea trees.
- ☐ The majority of the SPPE failures (85.7 percent) were categorized as internal leakage, which pose minimal risk—based on the extent of degradation of installed well safety systems and potential consequence to personnel and the environment—than other types of failures such as external leaks and failure to close.
- ☐ SSV failures account for 83 percent of all reported failures. The majority of the SSV failures were internal leakage (88.0 percent) and only 6.5 percent failed to close which posed a higher potential risk but did not lead to an HSE event.
- ☐ Subsurface safety valves (SCSSV, SSCSV) accounted for 13.4 percent of the reported failures.
- ☐ There were 12 failures where the valve failed to close: six SSVs located on the platform, and six subsurface safety valves located away from the platform. One of the failures occurred during a process upset, but it did not lead to an HSE event and the SSV was able to be repaired on location. The remaining failures were found during testing, which helps to ensure that the valve will function if it is needed.
- ☐ Of the 8 failure reports indicating the presence of H_2S, all 8 wells were associated with SSV failures.
- ☐ Of the 7 failure reports indicating the presence of CO_2, 5 were associated with SSV failures and 2 with SCSSV failures.
- ☐ Most of the equipment failures (96.4 percent) were detected through leakage testing.
- ☐ The most frequent reported causes of component failures were *wear and tear* (74.1 percent) and *scale buildup* (7.1 percent).
- ☐ Over 80 percent of the failures occurred on wells producing less than 500 BOE/day, with over half of those producing greater than 100 BOE/day. Only about 1.0 percent of the failures were associated with wells producing more than 10,000 BOE/day (high producers).

- ☐ The most commonly reported SPPE component failure was the gate and seat degradation in SSVs.
- ☐ Sand, scale, and corrosive environment were the most frequently reported naturally occurring well fluid conditions associated with SPPE failures

Next Steps: Opportunities for Improvement

The analysis of SPPE failure data confirms the most problematic components and operating conditions where improvement opportunities can be identified. To that end and to improve the accuracy of the information in the SafeOCS database, BTS will focus in the following data improvement areas:

1. SafeOCS is creating a guidance document to assist operators in reporting SPPE failures. The SPPE user guide will provide detailed instructions and definitions to OCS oil and gas industry operators for selecting and inputting data into the form, thereby improving the quality of data being reported and the analysis being conducted.
2. SafeOCS will revise the SPPE data collection form to further improve data quality and ensure all possible answers are capture correctly.
3. Depending on data availability, additional data quality efforts and data analysis will focus on:
    a. Measuring component life, in cycles or time;
    b. Identifying the most common causes and contributing factors to prioritize problem solving efforts;
    c. Collecting specific root cause investigation results and learnings from OEMs and third parties that may have industry-wide benefit; and
    d. Quantifying the operational impact in terms of production interruption when failures occur.

Appendix A: RELEVANT STANDARDS

30 CFR Part 250 – Oil and Gas Sulfur Operations in the Outer Continental Shelf

- Subpart A - General (§§ 250.101 - 250.199)
- Subpart B - Plans and Information (§§ 250.200 - 250.295)
- Subpart C - Pollution Prevention and Control (§§ 250.300 - 250.301)
- **Subpart D - Oil and Gas Drilling Operations (§§ 250.400 - 250.490)**
- Subpart E - Oil and Gas Well-Completion Operations (§§ 250.500 - 250.531)
- Subpart F - Oil and Gas Well-Workover Operations (§§ 250.600 - 250.620)
- **Subpart G - Well Operations and Equipment (§§ 250.700 - 250.746)**
- **Subpart H - Oil and Gas Production Safety Systems (§§ 250.800 - 250.892-250.899)**
- Subpart I - Platforms and Structures (§§ 250.900 - 250.921)
- Subpart J - Pipelines and Pipeline Rights-of-Way (§§ 250.1000 - 250.1019)
- Subpart K - Oil and Gas Production Requirements (§§ 250.1150 - 250.1167)
- Subpart L - Oil and Gas Production Measurement, Surface Commingling, and Security (§§ 250.1200 - 250.1205)
- Subpart M - Unitization (§§ 250.1300 - 250.1304)
- Subpart N - Outer Continental Shelf Civil Penalties (§§ 250.1400 - 250.1480)
- Subpart O - Well Control and Production Safety Training (§§ 250.1500 - 250.1510)
- Subpart P - Sulfur Operations (§§ 250.1600 - 250.1634)
- **Subpart Q - Decommissioning Activities (§§ 250.1700 - 250.1754)**
- ☐ Subpart R [Reserved]
- Subpart S - Safety and Environmental Management Systems (SEMS) (§§ 250.1900 - 250.1933)

Relevant Industry Standards Incorporated by Reference in 30 CFR 250 Subpart H

- ☐ ANSI/API Specification 6A (ANSI/API Spec. 6A), Specification for Wellhead and Christmas Tree Equipment, Nineteenth Edition, July 2004; Errata 1 (September 2004), Errata 2 (April 2005), Errata 3 (June 2006) Errata 4 (August 2007), Errata 5 (May 2009), Addendum 1 (February 2008), Addenda 2, 3, and 4 (December 2008)

- API Spec. 6AV1, Specification for Verification Test of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service, First Edition, February 1, 1996; reaffirmed April 2008
- ANSI/API Specification 17D, Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment, Second Edition, May 2011
- ANSI/API Recommended Practice 17H, Remotely Operated Vehicle Interfaces on Subsea Production Systems, First Edition, July 2004, Reaffirmed January 2009
- ANSI/API Specification Q1 (ANSI/API Spec. Q1), Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry, Eighth Edition, December 2007, Addendum 1, June 2010
- API 570, Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems, Third Edition, November 2009.
- ANSI/API Spec. 14A, Specification for Subsurface Safety Valve Equipment, Eleventh Edition, October 2005, Reaffirmed June 2012.
- ANSI/API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems, Fifth Edition, October 2005
- API RP 14C, Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms, Seventh Edition, March 2001, Reaffirmed: March 2007
- API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, Fifth Edition, October 1991; Reaffirmed January 2013
- API RP 14H, Recommended Practice for Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore, Fifth Edition, August 2007
- API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, Second Edition, May 2001; Reaffirmed January 2013

Final Rule, Oil and Gas and Sulfur Operations on the Outer Continental Shelf-Oil and Gas Production Safety Systems, 81 Federal Register 61,833, at 61,861 (September 7, 2016)

“If there is any conflict between any document incorporated by reference and the regulations, the regulations control; thus, the asserted intent of the developer of the standard does not constrain the terms of BSEE’s regulations.”

Other Standards Incorporated by Reference

- ANSI/ASME Boiler and Pressure Vessel Code, Section I, Rules for Construction of Power Boilers; including Appendices, 2004 Edition; and July 1, 2005 Addenda, and all Section I Interpretations
- ANSI/ASME Boiler and Pressure Vessel Code, Section IV, Rules for Construction of Heating Boilers including Appendices 1, 2, 3, 5, 6, and Non-mandatory Appendices B, C, D, E, F, H, I, K, L, and M, and the Guide to Manufacturers Data Report Forms, 2004 Edition; July 1, 2005 Addenda, and all Section IV Interpretations
- ANSI/ASME Boiler and Pressure Vessel Code, Section VIII, Rules for Construction of Pressure Vessels; Divisions 1 and 2, 2004 Edition; July 1, 2005 Addenda, Divisions 1, 2, and 3 and all Section VIII Interpretations
- API 510, Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration, Downstream Segment, Ninth Edition, June 2006
- API RP 2RD, Recommended Practice for Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), First Edition, June 1998; reaffirmed, May 2006, Errata, June 2009
- API RP 2SK, Recommended Practice for Design and Analysis of Stationkeeping Systems for Floating Structures, Third Edition, October 2005, Addendum, May 2008
- API RP 2SM, Recommended Practice for Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring, First Edition, March 2001, Addendum, May 2007
- API RP 14F, Recommended Practice for Design, Installation, and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class 1, Division 1 and Division 2 Locations, Upstream Segment, Fifth Edition, July 2008, Reaffirmed: April 2013
- API RP 14FZ, Recommended Practice for Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Zone 0, Zone 1 and Zone 2 Locations, First Edition, September 2001, Reaffirmed: March 2007
- API RP 14G, Recommended Practice for Fire Prevention and Control on Fixed Open-type Offshore Production Platforms, Fourth Edition, April 2007
- API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2, Second Edition, November

- ☐ API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2, First Edition, November 1997; Reaffirmed, August 2013
- ANSI/API RP 2N, Third Edition, "Recommended Practice for Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions", Third Edition, April 2015;
- ☐ API 570 Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems, Third Edition, November 2009

Appendix B: GLOSSARY AND ACRONYM LIST

Glossary

Accumulator: A pressure vessel charged with gas (nitrogen) over liquid and used to store hydraulic fluid under pressure for operation of blowout preventers (BOPs).

Casing: Piping into the well that allows fluids to move out of and into the drilled well.

Check Valve: A valve that allows fluid to flow in one direction, containing a mechanism to automatically prevent flow in the other direction.

Control Fluid: Hydraulic oil, water-based fluid, or gas which, under pressure, pilots the operation of control valves or directly operates functions.

Disable a mechanical barrier: To cause a mechanical barrier not to perform its intended function (for example, a failure that causes an annular preventer to fail to seal, or fail to open or close).

Flowline: Piping carrying a well's fluid stream from the wellhead to the first downstream process component.

Gate Valve: A valve that employs a sliding gate to open or close the flow passage.

Injection Well: A well in which oil and gas production waste is disposed.

Near Miss: A event that happened that could have led to an incident with adverse effects, but did not.

Production Well: A well in which oil or gas is extracted from.

Suspended Well: A subsea well that cannot be controlled or monitored from the host facility for 30 days or more, and may not be suspended for more than 24 months without additional permission.

Well Test Rate: A measurement of production rate in BOE, is equal to the barrels of oil plus the barrel oil equivalent of the produced gas, in million standard cubic feet per day (based on 175 BOE/MMSCFD, which is a typical Gulf of Mexico gas conversion factor).

Well Tree: An assembly of valves and other equipment fitted to the wellhead of a completed well to control production.

Wellhead: A mechanical portion covering the casing to allow the well to be connected to the tree.

Wireline: a cabling technology used on oil and gas wells to lower equipment or measurement devices into the well for the purposes of well intervention, reservoir evaluation, and pipe recovery. Slick line, a type of wireline, is a thin cable introduced into a well to deliver or retrieve tools downhole as well as to place and recover wellbore equipment such as plugs, gauges, and valves[10].

Acronym List

ANSI: American National Standards Institute

API: American Petroleum Institute

BSEE: Bureau of Safety and Environmental Enforcement

BTS: Bureau of Transportation Statistics

HSE: Health, Safety and Environment

OEM: Original Equipment Manufacturer

RCFA: Root Cause Failure Analysis

SME: Subject Matter Expert

[10] https://en.wikipedia.org/wiki/Wireline_(cabling); modified by ANL

Appendix C: Typical SPPE Valve Components

Component	SSV	USV	SCSSV	SSCSV	BSDV
Actuator	x	x	x		x
Ball	Rare	x	Rare		x
Direct Hydraulic Control System	x	x	x		x
Electro-Hydraulic Control Umbilical		x	x		
Emergency Shutdown (ESD) System	x	x	x		x
Flange	x	x			x
Flapper			x	x	
Flow Coupling			x	x	
Gate and Seat	x	x	Seat	Seat	x
Landing Nipple			x	x	
Ring Joints	x	x			x
Safety Lock			x	x	
Temperature Safety Element (TSE)	x	x	x		x
Valve Body	x	x	x	x	x

Appendix D: SPPE Certification and Classification

SPPE certifications fall under four types (Table 5). The Production Safety Systems Rule requires that SPPE be certified to ANSI/API Spec Q1. BSEE may exercise its discretion to accept and approve SPPE certified under other quality assurance programs. ANSI/ASME SPPE-1 was a previous standard (1996) containing certification criteria.

Table 4: Certification Status of Reported SPPE

SPPE Certification	Percent of Reports
Newly Installed certified SPPE pursuant to ANSI/API Spec Q1	13.5
Newly Installed certified SPPE pursuant to another quality assurance program	6.3
Previously certified under ANSI/ASME SPPE-1	69.4
Non-Certified SPPE	0.9
Not Answered	9.9

SPPE valves are categorized by different classes. SSVs, BSDVs, and USVs can be one of two service classes. Class 1 indicates a performance level requirement intended for use on wells that do not exhibit the detrimental effects of sand erosion. Class 2 indicates a performance level intended for use if a substance such as sand could be expected in the flow stream. Of the failed SSVs and BSDVs, 56.3 percent were Class 1 and 28.1 percent were Class 2. The other 15.6 percent of reporters did not specify a class. BSDVs are further categorized as either automatic or manual. All four BSDVs reported to SafeOCS were automatic.

The subsurface safety valves (SCSSVs and SSCSVs) have a different set of categories for class. Service classes are:

- ☐ Class 1: standard service only;
- ☐ Class 2: sandy service;
- ☐ Class 3: stress cracking;
- ☐ Class 3s: sulfide stress and chlorides in a sour environment;
- ☐ Class 3c: sulfide stress and chlorides in a non-sour environment; and
- ☐ Class 4: mass loss corrosion service.

Of the 13 reported SCSSVs and SSCSVs, four were Class 1, two were Class 2, four were both Class 1 and Class 2, and one was Class 3c. Two did not report the class.

Appendix E: HSE INCIDENTS

A health, safety, and environment (HSE) incident can include one or more of the following:

- ☐ One or More Fatalities
- ☐ Injury to 5 or more persons in a single incident
- ☐ Tier 1 Process Safety Event (API 754/IOGP 456)
- ☐ Loss of Well Control
- ☐ $1 million direct cost from damage of loss of facility/vessel/equipment
- ☐ Oil in the water >= 10,000 gallons (238 bbls)
- ☐ Tier 2 Process safety event (API 754/IOGP 456)
- ☐ Collisions that result in property or equipment damage > $25,000
- ☐ Incident involving crane or personnel/material handling operations
- ☐ Loss of Station-keeping
- ☐ Gas release (H2S and Other) that result in process or equipment shutdown
- ☐ Muster for evacuation
- ☐ Structural Damage
- ☐ Spill < 10,000 gallons (238 bbls)