Oil and Gas Production Safety System Events

2019 Annual Report

U.S. Department of Transportation
Office of the Secretary of Transportation
Bureau of Transportation Statistics

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ACKNOWLEDGEMENTS

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EXECUTIVE SUMMARY

The 2019 Oil and Gas Production Safety System Events Annual Report is based on 225 notifications reported to SafeOCS for safety and pollution prevention equipment (SPPE) events during the calendar year. These failures occurred during operations in the Gulf of Mexico (GOM) Outer Continental Shelf (OCS), where over 99 percent of all United States offshore production happens. The 225 failures occurred on 186 of 5,335 active wells[1] (3.5 percent) in the GOM OCS.

Fifteen out of 56 active operators submitted SPPE failure reports, compared to 14 of 58 operators in 2018. The 15 reporting operators account for 60.6 percent of active wells and 75.7 percent of production from the GOM OCS.

Of the 225 reported failures, 210 (93.3 percent) were on surface wells and comprised 172 surface safety valves (SSVs), 34 surface controlled subsurface safety valves (SCSSVs), and four subsurface controlled subsurface safety valves (SSCSVs). Of the remaining 15 failures (6.7 percent), eight were located subsea (two underwater safety valves (USVs), five SCSSVs, and one SSCSV), and seven were located on the facility (five boarding shutdown valves (BSDVs) and two gas lift shutdown valves (GLSDVs)).

Surface safety valves (SSV) experienced the most failures of any valve type, with nearly 77 percent of reported failures. The higher number of failures for SSVs may be partially explained by the higher frequency of testing and lower acceptable leakage rate for SSVs.

In 2019, approximately 11,849 SPPE valves were in service in 5,335 active wells in the GOM OCS. The total GOM SPPE failure rate is 0.28 percent, as compared to the 2018 rate of 0.24 percent.[2] The failure rates for each SPPE valve type range from 0.07 percent for USVs to as high as 0.88 percent for SSCSVs.[3] The low failure rate for USVs may be explained by the lower testing frequency (quarterly) and higher allowable leakage rate than other valve types.

SPPE failures were categorized based on the extent to which they degrade the installed well safety systems and potential consequences to personnel and the environment. None of the 225 reported SPPE failures were characterized as health, safety, and environmental (HSE) incidents, i.e., an event that results

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[1] An active well, for purposes of this report, is considered a well with SPPE valves providing a barrier to the fluids in the reservoir. Appendix C provides a complete definition.

[2] To improve the accuracy of SPPE failure rates, in 2019, BTS revised the calculation methodology to better account for required SPPE testing frequencies. Testing is associated with a greater likelihood of identifying a failure. See SPPE Failure Rates on page 21.

[3] The failure rate for SSCSVs spans from 0.44 percent to 0.88 percent, depending on the required testing frequency. See SPPE Failure Rates on page 21.

in consequences to the health or safety of personnel or the environment. Ten external leaks were reported: four resulting in small leaks of well fluids to the atmosphere, and the remaining six were leaks of control fluids (instrument air, instrument gas, or hydraulic fluid). All of the external leaks were too small to be considered HSE events. The majority of the SPPE failures (88.4 percent) were categorized as internal leaks, meaning the valve closed but failed to seal, allowing some fluid to flow through it. Internal leaks generally pose less risk than other types of failures, such as external leaks or the valve failing to close.

Most SPPE failures (85.3 percent) were associated with shallow water wells (depths of 200 meters or less) and low production wells. Over three quarters (83.6 percent) of the failures occurred on wells producing less than 500 barrel of oil equivalents (BOE) per day; more than half (53.8 percent) occurred on wells producing less than 100 BOE/day. These lower producing wells pose less risk than higher-producing wells. Less than 1.0 percent of the failures were associated with wells producing more than 5,000 BOE/day, and these wells had no failures to close on the platform or external leaks, the most significant types of reported failures.

Valve seat degradation was the most commonly reported factor contributing to SPPE failures, reported for 60.4 percent of failure events. Factors related to the operating environment—sand cut erosion, atmospheric or chemical corrosion, paraffin, debris, and scale—were designated as contributing factors in 20.9 percent of reports, with sand cut erosion making up most of these (10.2 percent).

Most of the reported equipment failures (87.1 percent) were found during routine leakage tests. Examination of the 12 failures (5.3 percent) found during an emergency shutdown (ESD) response showed that all occurred during ESD testing rather than during an emergency event. Repair was the most commonly reported most significant corrective action for an event, reported for 58.7 percent of events.

Wear and tear was the most frequently reported root cause, reported for 162 of 225 failures (72.0 percent). BTS performed several analyses to gain more insight into the nature of wear and tear failures, given their sizable proportion. Among 162 wear and tear failures, valve seat degradation was reported for 118 (72.8 percent). Erosion (sand) or corrosion (chemical or atmospheric) was designated as a contributing factor in 17.3 percent of wear and tear failures, with sand cut erosion making up most of these (11.7 percent). A repair was the most common corrective action for wear and tear failures, reported for 121 of 162 (74.7 percent) failures.

BTS performed an analysis of SPPE time to failure to further explore what constitutes normal wear and tear. For 49 of 162 wear and tear failures, the reporter provided either the date of installation or date of last repair, ranging from under one year to over 20 years. For 40.8 percent of these failures, the valve failed within one year of its installation or last repair. For nearly two-thirds, the valve failed within three years.

BTS has identified several focus areas to continue to improve the accuracy of the information in the SafeOCS database and share learnings from SPPE failures with the industry and other stakeholders:

- Revise the data collection form to improve data quality further and ensure answers are captured correctly.
- Continue efforts to improve exposure data and measures.
- Work with stakeholders to improve the data collection process by focusing in the following areas:
  - Improve operator participation in reporting.
  - Identify opportunities to improve reporting of specific root cause failure analysis results and learnings that may have industry-wide benefits.

1 Introduction

SafeOCS, a confidential reporting program, was established in August 2013 through an interagency agreement between the Department of Transportation's Bureau of Transportation Statistics (BTS) and the Department of the Interior's Bureau of Safety and Environmental Enforcement (BSEE) for the purpose of advancing oil and gas operations on the Outer Continental Shelf (OCS). The objective of the program is to capture and share essential information across the industry about accident precursors and potential hazards associated with offshore operations.

The SafeOCS program includes reports of safety and pollution prevention equipment (SPPE) failures as mandated under the Oil and Gas Production Safety Systems Rule (subpart H).[4] The rule requires operators to submit SPPE failure reports when specific SPPE does not perform as designed and codifies industry reporting practices found in relevant American Petroleum Institute (API) standards and specifications. Appendices A and B provide background information on the regulatory requirements.

The interagency agreement requires BTS to publish a report on findings, emerging trends on SPPE, modifications made to the data collection process, and lessons learned. This report is the third annual report on SPPE failures. Other key information provided in the report includes operational impact and failure causes. All data analyses are based on reported SPPE component failures occurring on production facilities in the Gulf of Mexico (GOM) OCS. BSEE defines a failure as any condition that prevents the equipment from meeting its functional specifications.[5] In this report, the terms notice, notification, and event generally refer to reported equipment failures and are used interchangeably. Appendix C contains a glossary with detailed definitions of common terms.

As with the 2018 report, the 2019 analyses reconcile the SPPE data reported to SafeOCS using BSEE Incident of Noncompliance data (INC data) and Well Activity Report data (WAR data). In 2019, BTS also analyzed data from the U.S. Department of the Interior (DOI) Oil and Gas Operations Reports – Part A (OGOR-A) forms, which provide well shut-in status information in addition to production volume information. The use of these additional data sources resulted in a better approximation of the complete set of records for failure events that occurred in the GOM OCS during 2019 operations. Importantly, SPPE failures identified in the INC, OGOR-A, and WAR data were used only as supporting information. They have not been added to the total number of SPPE failure events reported to SafeOCS.

[4] The rule is codified primarily in 30 CFR part 250, subpart H. The failure reporting requirement is codified in 30 CFR 250.803.
[5] 30 CFR 250.803(a).

Additionally, to characterize failures with appropriate context, other BSEE databases were used. Specifically, BSEE well test data, well production volumes extracted from OGOR-A forms, and SPPE installation data were used. See the Data Collection and Validation section of this report for more information. Appendix D also includes information on how these data sources were used.

As was done with last year's report, BTS retained subject matter experts (SMEs) to assist in reviewing failure notifications for accuracy and consistency. These are experts in production operations, subsea engineering, equipment testing, well equipment design and manufacturing, root cause failure analysis, quality assurance and quality control, and process design. SMEs also provided support for review of the BSEE-provided data to further enhance the SafeOCS data analysis.

2 Safety and Pollution Prevention Equipment

In general, safety and pollution prevention equipment (SPPE) promotes the safety and protection of human, marine, and coastal environments. The specific SPPE covered by subpart H protects personnel and the environment by controlling the flow of well fluids (crude oil, natural gas, and water), especially in case of an emergency or system failure. The SPPE consists of specifically designated safety valves, actuators, and their control systems, which are required by BSEE regulations, industry standards, and in most cases, company policies. SPPE includes the following valve types:[6]

- Surface Safety Valves (SSVs)
- Boarding Shutdown Valves (BSDVs)
- Underwater Safety Valves (USVs)
- Subsurface Safety Valves
  - Surface Controlled Subsurface Safety Valves (SCSSVs)
  - Subsurface Controlled Subsurface Safety Valves (SSCSVs)
- Gas Lift Shutdown Valves (GLSDVs)

Surface Wells vs. Subsea Wells

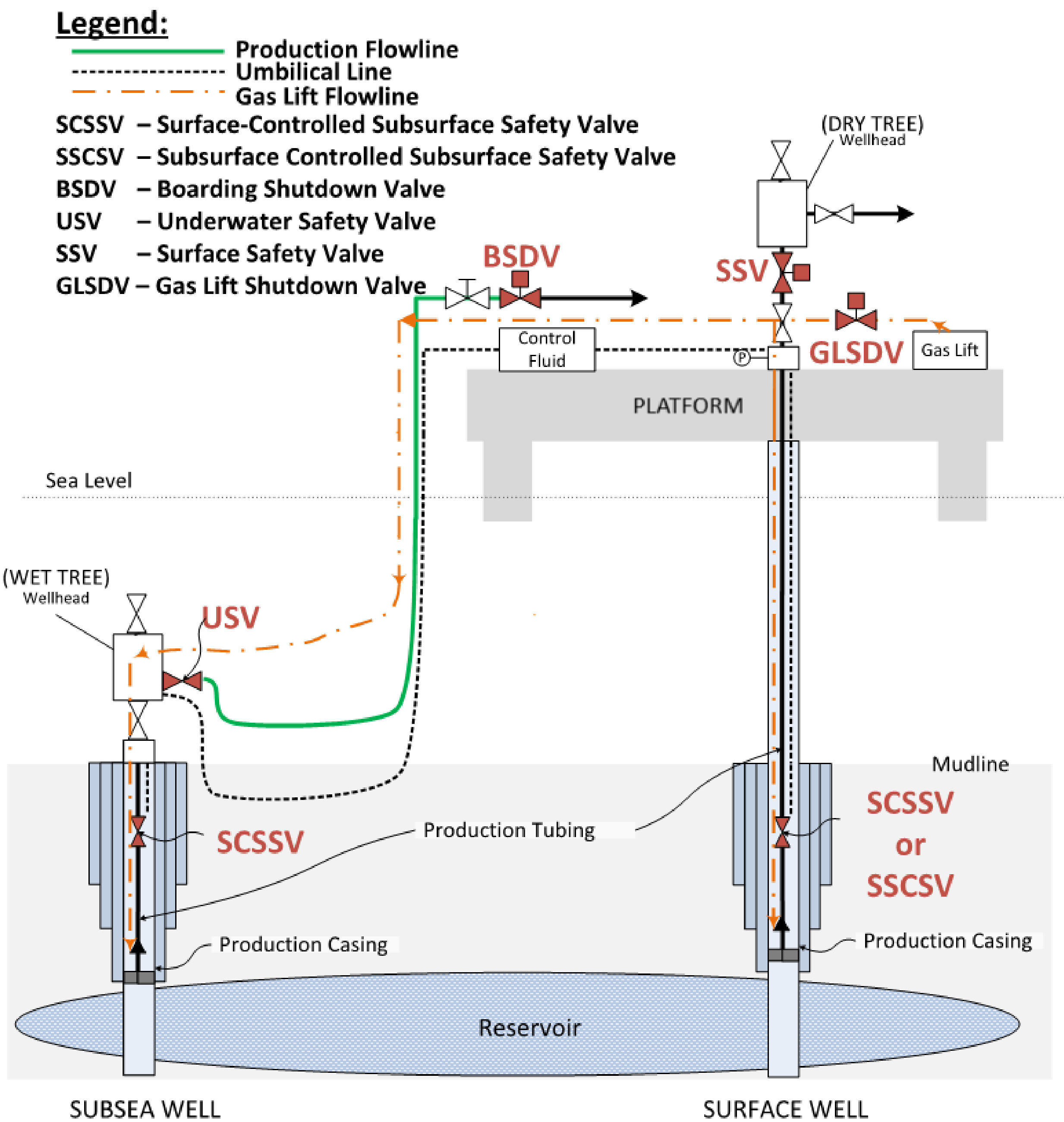
The SPPE valves are found in both surface wells and subsea wells. Surface wells have dry trees or direct vertical access (DVA) trees located above sea level on top of the well. Their location allows the operator direct access to the wellbore from the production platform. Subsea wells have wet trees located on the seafloor. Their location allows access to the wellbore only via production flowlines to a permanently installed production platform (for production purposes) or from a floating rig or intervention vessel (for intervention purposes). Figure 1 illustrates the typical locations of these SPPE valves, although variations exist within well trees in the field.

A typical surface well will be equipped with at least one subsurface safety valve (SCSSV or SSCSV) in the tubing below the seafloor (mudline) and an SSV on the wellhead. Similarly, a subsea well will be equipped with at least one subsurface safety valve and a USV. However, SSCSVs are no longer allowed by BSEE in new subsea wells due to reliability issues and long repair times caused by the need for an intervention vessel. Per subpart H, a production master valve (PMV) or production wing valve (PWV) may qualify as a USV under API Spec. 6A and API Spec. 6AV1.[7] They provide redundancy in the equipment to allow for

[6] 30 CFR 250.801.
[7] 30 CFR 250.833.

secondary valves, should one fail. In addition, the flowline that transports well fluids from one or more subsea wells will be equipped with a BSDV located on the production facility.

Figure 1: Equipment Schematics



SOURCE: U.S. Department of Energy, Office of Science, Argonne National Laboratory

SPPE Valve Types

SPPE valves are operated in the open position to allow the production from the well to flow. They are designed to close automatically if a control system failure occurs (i.e., fail-safe valves) or if there is an operational need to stop the flow from the well. All SPPE valves are considered isolation valves and mechanical barriers because they are designed to stop the flow of well fluids to protect personnel, equipment, and the environment. 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.

All SPPE valves are automatically operated, meaning a hydraulic or pneumatic actuator is used to open or close the valve. Further, all SPPE valves tie into the control system of the operating platform. SPPE valves can be opened or closed for routine operations by the operator from the platform control system.

Most SSVs and USVs are sliding gate valves operated either hydraulically (using hydraulic oil pressure) or pneumatically (using gas pressure). SSVs are found on surface wells (on dry trees), whereas USVs are located on subsea wells (on wet trees). BSDVs, utilized for flowlines of subsea wells and located on the platform, are commonly gate or ball valves. Similarly, GLSDVs are either gate or ball valves, and are most commonly used on surface wells, but could be installed on subsea wells. In many cases, GLSDVs are located on the platform on the gas lift supply line for a subsea field with one or more subsea wells. Both the BSDVs and the GLSDVs protect the platform and personnel against the flow from subsea wells.

Subsurface safety valves, located in the tubing of wells, are either surface controlled (SCSSV) or subsurface controlled (SSCSV). The SCSSV is a fail-safe, flapper-type valve that uses hydraulic control pressure from the surface to hold the flapper open to allow flow from the well. SCSSVs are typically full opening valves that allow for higher well production rates and intervention work below the SCSSV. The SCSSV is an integral part of the tubing and can only be retrieved for repairs if the tubing is removed from the well (i.e., tubing-retrievable SCSSV). As an alternative to pulling the tubing to retrieve a failed SCSSV, a smaller wireline-retrievable SCSSV can be installed in the well after locking open the original SCSSV. This type of valve may lower the well flow rate and needs to be pulled to allow future deeper interventions in the well. However, because it is surface controlled it is preferred over the SSCSV discussed below.

The SSCSV is a normally open valve in the well's tubing that closes at a predetermined flow rate or pressure. The SSCSV is installed or removed (i.e., run or pulled) using wireline and typically set in a landing nipple[8] in the well's tubing string. The valve is typically held open by a spring. The differential pressure across the valve causes it to close and stop the well from flowing at flow rates higher than the designed shutdown rate. The SSCSV can be retrieved for maintenance or to allow for other downhole operations. SSCSVs may be used in surface wells but are no longer allowed in new subsea wells, as mentioned above.

Function and Leakage Tests

All SPPE valves must be function tested and leak tested per the requirements of subpart H.[9] Table 1 summarizes the general testing frequencies and leakage requirements. However, exceptions can apply for different types of wells, subject to BSEE's approval.[10]

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 (oil or water) or 15 scf per minute of gas	Quarterly, not to exceed 120 days
SCSSV	400 cc per minute of liquid (oil or water) or 15 scf per minute of gas	Semiannually, not to exceed 6 calendar months
SSCSV	Not applicable	Remove, inspect, and repair or adjust semiannually, 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.
GLSDV	Zero leakage	Monthly, not to exceed 6 weeks

NOTE: Units of cc per minute are cubic centimeters (also seen as cm3) per minute. Units of scf per minute are standard cubic feet per minute.

[8] A landing nipple is a type of completion component that provides a seal area and a locking profile. See Appendix C for full definition.
[9] 30 CFR 250.873, 250.880.
[10] Additional information and requirements for new wells and wells that are completed and disconnected from monitoring capability are provided in the CFR.

3 Data Collection and Validation

Data Confidentiality— CIPSEA

The Confidential Information Protection and Statistical Efficiency Act of 2002 (CIPSEA) protects the confidentiality of all data submitted directly to SafeOCS. 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 provision means that BTS can only publish summary statistics and data analysis results. Incident microdata collected by SafeOCS may not be shared or used for regulatory purposes. Information submitted under this statute is protected from release to other government agencies, including BSEE, and from Freedom of Information Act (FOIA) requests, subpoenas, and legal discovery.

SPPE Failure Reporting

SPPE failures can occur when the valve is automatically or manually called upon via the control system to close. Operators must report failures of SPPE systems and their components to BSEE or BSEE's designee and original equipment manufacturers (OEMs) within 30 days of discovering and identifying a failure. BSEE has directed the industry to submit all failure notifications to SafeOCS. During the reporting period, operators submitted the notifications in several formats: Microsoft Word documents, PDFs, and website forms. The 2019 annual report is based on a total of 225 notifications reported to SafeOCS for events that occurred during the calendar year.

Data Validation

It is standard practice for statistical agencies to seek out additional data sources to validate collected data. BTS used data provided by BSEE to validate SafeOCS data and to enhance data analysis. The specific BSEE data sources are listed below. Appendix D provides more information about the methodology used in evaluating each data source.

Well Activity Reports (WARs)

Operators are required to provide a summary of daily activities in all Outer Continental Shelf (OCS) regions (Gulf of Mexico (GOM), Pacific, and Alaska) via WARs weekly in the GOM and daily in the Pacific and Alaska regions.[11] The well activities reported in the WARs include work accomplished on OCS wells during all phases (drilling, completion, workover, recompletion, non-rig interventions, and abandonments), including any repairs or replacements of subsurface SPPE valves (SSCSVs and SCSSVs).

[11] 30 CFR 250.743.

BTS reviewed the WAR reports for non-rig operations (e.g., wireline operation reports) to cross-reference the timing and occurrence of subsurface SPPE failures and determine which were reported to SafeOCS.

Well Test Reports

BSEE requires operators to submit well test reports detailing daily oil, gas, and water volumes at least once every six months for each producing well.[12] Volumes are reported in barrels of oil per day, thousands of cubic feet of gas per day, and barrels of water per day.[13] BTS reviewed well test reports to provide context for each failure's potential impact by using the fluid volume information to categorize wells and associated events.

Well Production Volumes – OGOR-A

Operators report well production volume information to the Department of the Interior through Oil and Gas Operations Reports – Part A (OGOR-A). The OGOR-A data provides each well's monthly production volumes of oil, gas, and water, as well as the number of days each well produced during a given month. BTS used production volume information from OGOR-A data to determine the well rate and water cut for active wells and wells with SPPE failures. This information facilitates a comparison of SPPE failures across groups of wells with similar characteristics.

Well Shut-in Status – OGOR-A

In addition to well production volume information, operators also provide information on shut-in wells (i.e., wells that are closed and not producing) in their OGOR-A submissions. The OGOR-A data contains various monthly "shut-in reason" codes for the status of each shut-in well that can be used to determine the month in which an active well goes from producing status to shut-in status and the reason for the status change. BTS used well shut-in status information from OGOR-A data to cross-reference the timing and occurrence of failures reported to SafeOCS and identify failures that may not have been reported to SafeOCS.

SPPE Installation Data

Operators report all SPPE installations to BSEE, and these are captured in a database that includes valve data such as type of valve, location, and installation date. BTS used SPPE installation data to estimate the total number of SPPE valves associated with wells in the GOM.

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[12] Procedures for OCS well test reporting are codified in 30 CFR part 250 subparts K and L.
[13] 30 CFR 250.1151(a)(2).

Incidents of Noncompliance (INCs)

Field INCs may be issued by BSEE inspectors whenever they are on a platform and witness deficiencies. For SPPE, such deficiencies could be witnessed during testing as part of an annual inspection. These deficiencies are regulatory violations, and depending on the severity of the violation, BSEE may issue an INC with a warning, component shut-in, or facility shut-in enforcement action. The INC will provide the operator with direction on how to come into compliance and take appropriate action. BTS used the INCs involving 2019 SPPE failures to cross reference and validate SPPE failures reported to SafeOCS during the same period and potentially further enhance the quality of information collected. While failures associated with INCs do not capture all possible failures that occur, the INC database provides an additional source to identify failures that occurred in the GOM in 2019 but may not have been reported to SafeOCS, as well as provide more detail for reported events.

Borehole Data

Operators report to BSEE various information about OCS boreholes (i.e., the hole drilled for reservoir exploration or installation of a production well), such as location and depth information. BTS used borehole data to determine the water depth for active wells and wells with SPPE failures. This information facilitates a comparison of SPPE failures across groups of wells with similar characteristics.

4 Data Analysis

SPPE Numbers at a Glance

Subpart H covers production operations on the Outer Continental Shelf (OCS), which includes BSEE's Gulf of Mexico (GOM), Pacific, and Alaska regions. For 2019, SafeOCS received equipment failure notifications for operations in the GOM only, which accounts for over 99 percent[14] of all offshore production in the United States. Exact locations of reported equipment failures are not disclosed in this document to protect the data's confidentiality.

SafeOCS received 225 SPPE failure notifications for 2019. Table 2 provides an overview of the reported SPPE failures in 2019 compared to the previous two years. The 225 failures occurred on 186 of 5,335 total active wells[15] (3.5 percent) in the GOM OCS. The number of active wells was slightly lower than in 2018; however, production increased from an average of 2.24 MMBOE/day (approximately 818 MMBOE total) to 2.74 MMBOE/day (approximately 1,001 MMBOE total). The number of reporting operators (operators who reported failure notifications) increased from 14 to 15, increasing from 24.1 percent to 26.8 percent of total operators in the GOM. Although the number of active wells operated by the reporting operators fell from 66.8 to 60.6 percent in 2019, their share of production in the GOM OCS increased from 62.3 to 75.7 percent. These operators are also generally reporting more comprehensive information than in 2018 reports. However, at least 34.6 percent of SPPE failures were unreported from evaluating other sources of SPPE failure information.

As discussed in the section Details of Reported Equipment (page 18), the methodology for calculating failure rate was revised in 2019 to consider annual testing frequencies, as most failures are detected during testing. The methodology was also applied to prior years for purposes of comparison across years. The total GOM SPPE failure rate in 2019 is 0.28 percent, as compared to the rate of 0.24 percent in 2018 (calculated under the revised method). The failure rates for each SPPE valve type span from 0.07 percent for USVs to as high as 0.88 percent for SSCSVs.

[14] BSEE Data Center, Outer Continental Shelf Oil and Gas Production data, December 2019 volumes.
[15] An active well, for purposes of this report, is considered a well with SPPE valves providing a barrier to the fluids in the reservoir. Appendix C provides a complete definition.

Table 2: SPPE Numbers at a Glance

	2017	2018	2019
Operator Summary:			
Active Operators	57	58	56
Producing Operators	55	53	53
Reporting Operators (Percent of Active Operators)	7 (12.3%)	14 (24.1%)	15 (26.8%)
Reporting Operators' Percent of Active Wells	32.6%	66.8%	60.6%
Reporting Operators' Percent of Production	39.8%	62.3%	75.7%
GOM Production Summary:			
Active Wells:			
Total Active Wells	5,624	5,476	5,335
Wells with SPPE Failure	98 (1.7%)	162 (3.0%)	186 (3.5%)
Average Daily Production Rate:			
Daily Prod. - Total Active Wells (BOE/day)	2,206,049	2,242,236	2,741,291
Daily Prod. - Wells with SPPE Failure (BOE/day)	43,700 (2.0%)	62,507 (2.8%)	68,186 (2.5%)
SPPE Failure Summary:			
SPPE Failures Reported to SafeOCS*	**112**	**204**	**225**
Surface Well SPPE Failure Events	108	198	210
Subsea Well SPPE Failure Events	4	6	15
SPPE Failures Identified from Other Sources**	104	107	150
SPPE Failures Identified from Other Sources and Not Reported to SafeOCS†	100 (47.2%)	62 (23.3%)	119 (34.6%)
SPPE Failure Rates:			
Installed SPPE Valves‡	12,373	12,174	11,849
SPPE Valve Failure Rate‡	0.13%	0.24%	0.28%
SPPE Failure Types:			
HSE Incident	0	0	0
External Leak	4	13	10
Failed to Close on Platform	6	13	7
Internal Leak on Platform	88	139	164
Failed to Close Away from Platform	6	17	14
Internal Leak Away from Platform	8	13	35
Failed to Open	2	6	4

KEY: HSE—Health, Safety, and Environment; INC—Incident of Noncompliance: WAR—Well Activity Report; SPPE—Safety and Pollution Prevention Equipment.

NOTE:

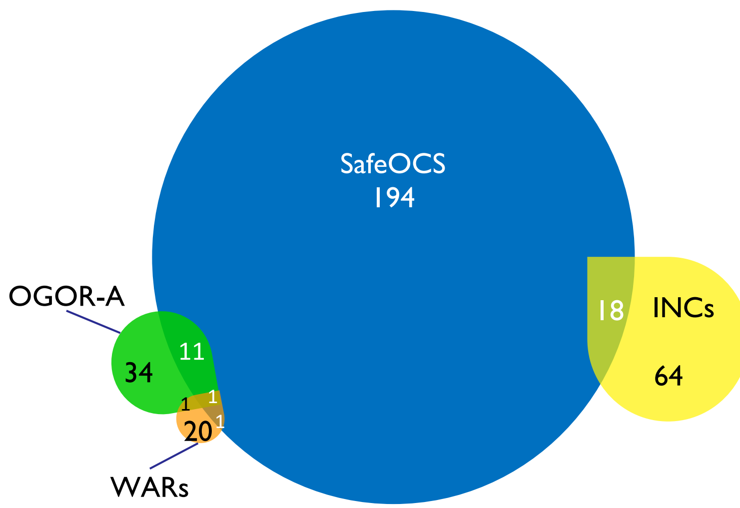
1. * This total does not include SPPE failures identified in the INC, WAR, or OGOR-A data.
2. ** For 2017 and 2018, "Other Sources" includes INCs and WARs. For 2019, it includes OGOR-A data in addition to INCs and WARs.
3. † Percentage calculation: 119 / (225 + 119) = 34.6%
4. ‡ The 2017 and 2018 rates differ from those published in earlier annual reports because a revised method was implemented in 2019. See SPPE Failure Rates on page 21.

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

Completeness of Failure Event Reporting

As mentioned above, the 2019 analyses reconcile the SPPE data reported to SafeOCS using INC data, WAR data, and OGOR-A data. The use of these additional data sources resulted in a better approximation of the complete set of records for failure events that occurred in the GOM OCS during 2019 operations. A review of all the available data found 344 unique SPPE failures in 2019. Figure 2 is a bubble plot showing the overlaps of the four databases. Of the 344 failures, 194 were reported to SafeOCS only, 119 were not reported to SafeOCS, and 31 were both reported to SafeOCS and found in the INC, WAR, or OGOR-A data. Over a third (119 of 344 or 34.6 percent) of SPPE failures identified in BSEE's INC, WAR, or OGOR-A records were not reported to SafeOCS. Therefore, reporting of SPPE failures to SafeOCS appears to be incomplete. The findings for each of the additional data sources are described in more detail below.

Figure 2: Sources of SPPE Failure Records



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

WAR Data

Analysis of the WAR data indicates that 23 subsurface safety valve failures were reported in WARs during 2019. Only one of the failures (one SCSSV) was reported to SafeOCS during 2019. Of the 23 SPPE failures, 21 were associated with SCSSVs, and two were associated with an SSCSV. In most cases, the SCSSV failures resulted in the tubing-retrievable SCSSV being "locked open" while a wireline-retrievable SSCSV or SCSSV was installed in the well. Determining the cause of these failures from the WAR data is difficult as the available data is limited to the operational repair activities rather than the valve operating history.

WARs may also include preventive maintenance reports, such as the required removal of a valve for testing. Importantly, BTS distinguishes between preventive maintenance reports and failure events when evaluating the WARs, and the 23 failure events found in WARs represent only failure events.

INC Data

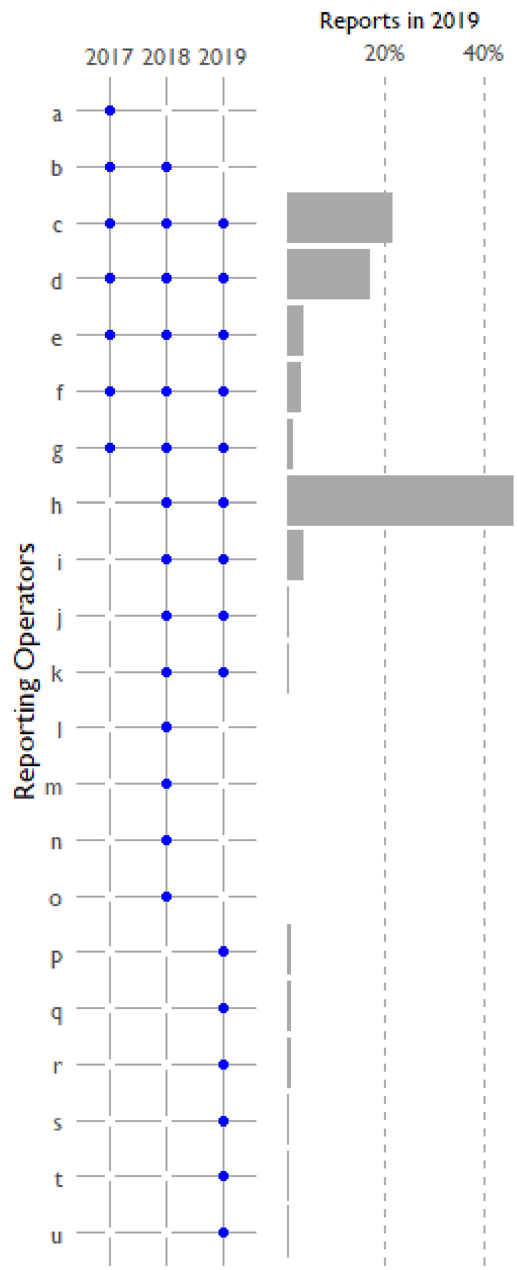
Analysis of the INC data shows that 82 SPPE failures were documented in the BSEE INC database for 2019, of which 18 were reported to SafeOCS. Importantly, the number of INCs involving SPPE valves represent only those failures occurring while BSEE is visiting the platform (i.e., a subset of all failures).

OGOR-A Data

Additional SPPE failures were also found using the BSEE OGOR-A data. A total of 47 SPPE failures were documented in the BSEE OGOR-A database for 2019, of which 12 were reported to SafeOCS.[16] Of the 47 SPPE failures found in OGOR-A, 22 were SSV failures, and 25 were SCSSV failures.

The WAR, INC, and OGOR-A data were also analyzed to determine whether any failures were recorded in more than one dataset. One failure was recorded in both the OGOR-A and WAR datasets, and one failure was recorded in the OGOR-A, WAR, and SafeOCS datasets. No failures from OGOR-A or WAR datasets were found in the

Figure 3: Reporting of SPPE Failures by Operator Across Years



NOTE: Operator names are not listed to preserve reporter confidentiality**.**

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

[16] For additional discussion of how these failures were identified, see Well Shut-in Status – OGOR-A on page 11.

INC dataset.

Who Reported Equipment Events

Figure 3 shows the percentage of SPPE reported failures by operator. There were 56[17] active operators in the GOM OCS listed as operating active wells in 2019 (58 in 2018 and 57 in 2017). Fifty-three (53) operators, out of 56, had production from the GOM OCS in 2019 (i.e., producing operators). The remaining three operators were associated with active wells but without production in 2019. Operators with non-producing wells are still responsible for testing their SPPEs and maintaining their wells.

Fifteen (15) out of the 56 active operators submitted SPPE failure reports, compared to 14 of 58 in 2018. The top three reporting operators (by the number of failure reports) accounted for 84.9 percent of the failure reports and 42.6 percent of the active wells in the GOM OCS. The operators who did not report in 2018 contributed 4.0 percent of the 2019 reports.

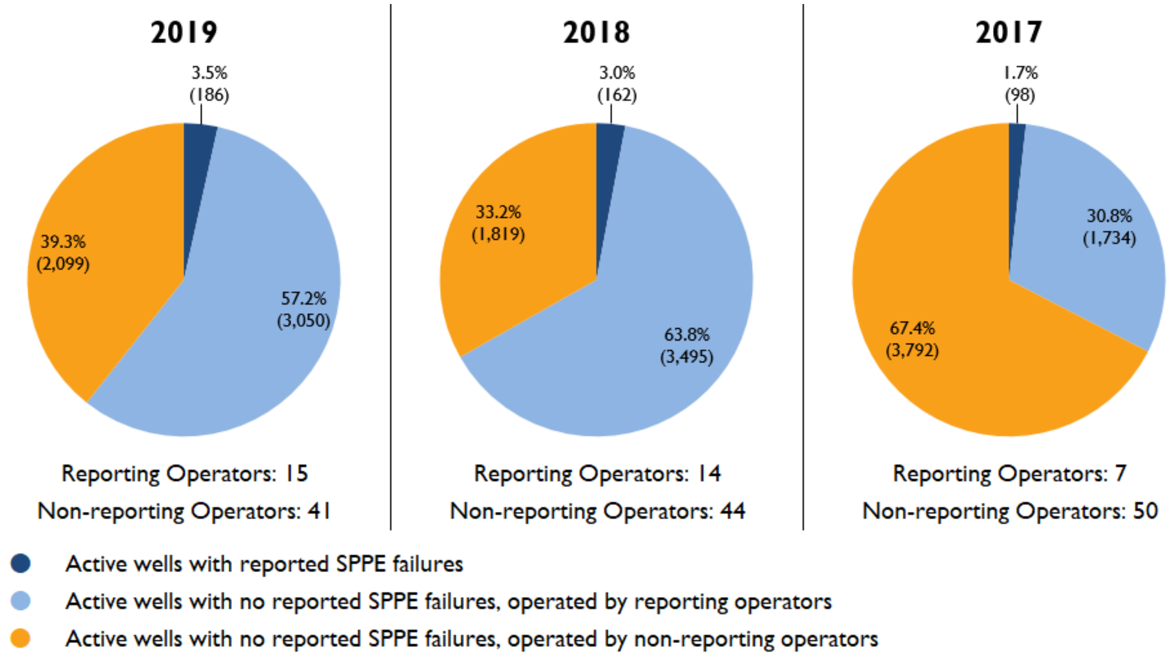
Figure 4 shows the distribution of active wells between reporting and non-reporting operators for the last three years. Of the 5,335 active wells in 2019, 186 were associated with one or more reported SPPE failures. The 15 reporting operators represent 26.8 percent of the 56 operators, but they operate 60.6 percent of the active wells. These 15 operators also account for 75.7 percent of production from the GOM OCS, as compared to the 2018 value of 62.3 percent. The remaining 41 operators with no reported failures operate 39.3 percent of the active wells and produce 24.3 percent of oil and gas produced in the GOM.

Reporting to SafeOCS varied among operators with SPPE-related INCs. BSEE's INC data detailed SPPE related INCs for 20 operators in 2019:

- Two (2) reported all their SPPE failures with INCs to SafeOCS,
- Three (3) reported a small percentage of their SPPE failures with INCs to SafeOCS, and
- Fifteen (15) did not submit any SPPE failures to SafeOCS.

[17] The number of operators with active wells was determined by using the Oil and Gas Operations Reports-Part A from BSEE for 2019.

Figure 4: Active Wells and Reporting Status of Operators



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

Details of Reported Equipment

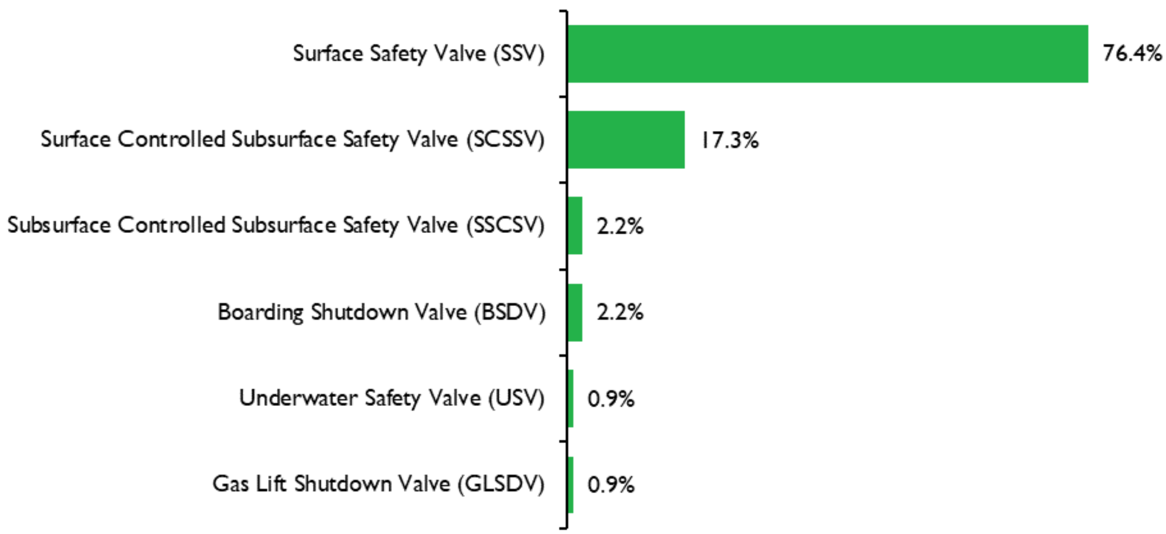
As stated above, SPPE includes six main valves in the well or production stream that directly control the flow of hydrocarbons:

- SSV—Surface Safety Valves,
- BSDV—Boarding Shutdown Valves,
- USV—Underwater Safety Valves,
- SCSSV—Surface Controlled Subsurface Safety Valves,
- SSCSV—Subsurface Controlled Subsurface Safety Valves, and
- GLSDV—Gas Lift Shutdown Valves.

Of the 225 reported failures, 210 (93.3 percent) were on surface wells (dry trees) and comprised 172 SSVs, 34 SCSSVs, and four SSCSVs. Of the remaining 15 failures (6.7 percent), eight were located subsea (two USVs, five SCSSVs, and one SSCSV), and seven were located on the facility (five BSDVs and two GLSDVs). All but one of the reported failures were on producing wells, and one failure was reported on an injection well. The low number of failures on subsea wells will be further evaluated with additional well data, as discussed under the *Next Steps* section.

Figure 5 illustrates failure proportions by the SPPE valve type. Nearly 77 percent of the failures reported were on SSVs, even though SSVs represent just under half of the SPPE population. SCSSVs have the second-highest number of failures (17.3 percent). The required testing frequency varies across the SPPE valves (Table 1), creating the potential for identifying more failures in one type of valve versus another. For example, SCSSVs are required to be tested every six months. In contrast, SSVs are tested monthly, leading to a potential six-fold higher likelihood of identifying a failure for SSVs than SCSSVs. In addition, the accepted leakage rates also differ among the valves with zero leakage permissible in SSVs and BSDVs, compared to 400 cubic centimeters (cc) per minute of oil or 15 standard cubic feet (scf) per minute of gas permissible for USVs and SCSSVs. These two factors partially explain why more failures were identified in SSVs than the other SPPE valve types.

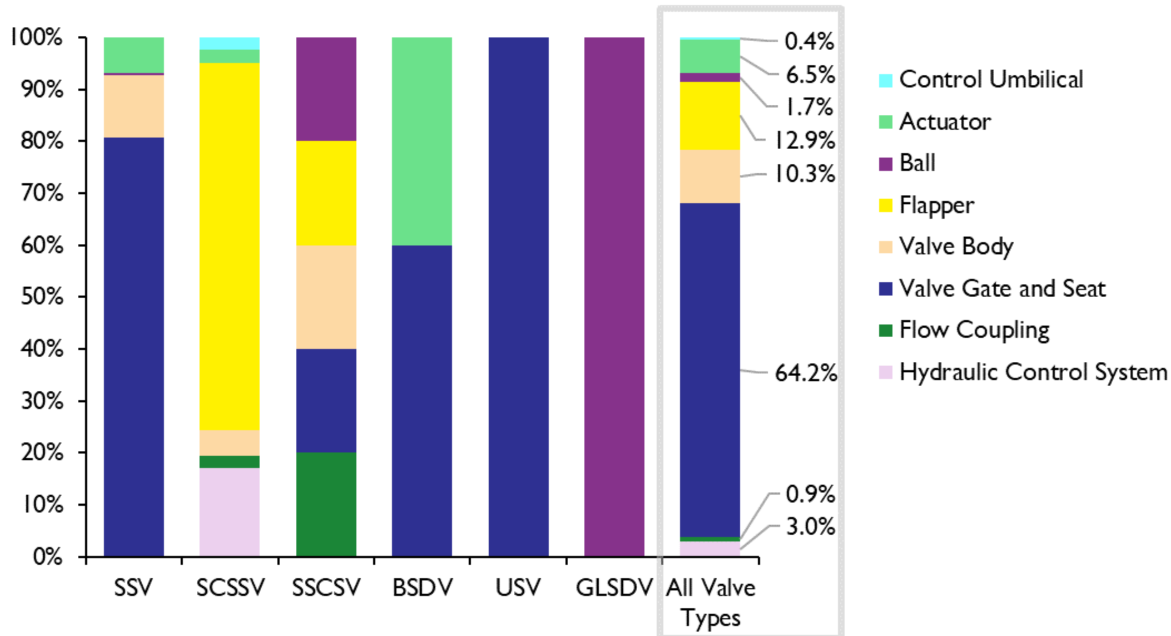
Figure 5: Reported SPPE Events by Valve Type



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

Multiple components make up each SPPE valve. Appendix E lists SPPE valves and their corresponding components. Figure 6 shows the type and number of components that failed within each valve type for failures reported to SafeOCS. For columns other than the rightmost one, the percent of each component failure is based on the total of each valve, not the total reported failures. For example, 100 percent of GLSDV failures were ball failures, but only two GLSDV failures were reported. Failures of certain components could have a higher consequence than others. For example, the actuator's failure could prevent the valve from closing when it is called upon, possibly extending the time of the event that triggered the valve closure. Flappers and valve gates and seats, on the other hand, are internal components. If they fail to seal, leakage would initially be contained internally. The most common component failure reported was the valve gate or seat, comprising 149 of 232 (64.2 percent) reported component failures.[18]

Figure 6: Failed Components within SPPE Valves Reported to SafeOCS



KEY: BSDV—Boarding Shutdown Valve; GLSDV—Gas Lift Shutdown Valve; SCSSV—Surface Controlled Subsurface Safety Valve; SSCSV—Subsurface Controlled Subsurface Safety Valve; SSV—Surface Safety Valve; USV—Underwater Safety Valve.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

Exposure Data

SafeOCS uses exposure measures to estimate the population of equipment that could be subject to failure and quantify its characteristics. Exposure measures are sometimes referred to as denominator data or normalizing data because they represent the population in terms of statistical values.

For SPPE, exposure data quantify 1) the population of SPPE that could be called on to perform its functional specifications or 2) the purpose and characteristics of that population. These exposure data provide denominator information, facilitating comparison among different types of SPPE and well environments. The following exposure measures were used in analyses of the 2019 SPPE failures.

- **Number of SPPE installations**: The total number of SPPE valves associated with wells in the

[18] Reporters identified 232 failed components in the 225 failure events; seven failure events included two failed components.

GOM OCS. See SPPE Installation Data, page 11, for more detail about this data source.

- **SPPE failure rate denominator**: The number of installed valves multiplied by the number of tests required annually. The failure rate denominator differed between valve types, due to a differing number of installations and required testing frequencies. This measure is discussed in more detail under SPPE Failure Rates, page 21.
- **Number of active wells**: The number of active wells in the GOM OCS. For the annual report, an active well is a well with SPPE valves providing a barrier to reservoir fluids (see full definition in Appendix C). The active wells were further grouped by several criteria to facilitate the comparison of SPPE failures across groups.

  - **Water depth**: The number of active wells grouped by water depth in meters.
  - **Well rate**: The number of active wells grouped by production rate in average BOE/day.
  - **Water cut**: The number of active wells grouped by water cut. Water cut is the ratio of water produced compared to the volume of total liquids produced.

These measures, with corresponding analyses, are further discussed below. SafeOCS also uses exposure measures to quantify the number of operators associated with active wells and hydrocarbon production by the operator, discussed above in the section titled Who Reported Equipment Events (page 17).

SPPE Failure Rates

To improve the accuracy of SPPE failure rates, in 2019, BTS revised the calculation methodology to better account for required SPPE testing frequencies. Testing is associated with a greater likelihood of identifying a failure. Most SPPE failures (87.1 percent) were detected through leakage testing (see How Failures Were Detected, page 34). Some valve types are required to be tested more frequently than others. Adjusting for varying testing frequencies among valve types can reduce the potential for ascertainment bias, which can occur when certain valves in the SPPE population are evaluated for potential failure more often than other types.

Table 3 shows the SPPE failure rates based on the total population of each valve type and its required testing frequency. The last column in Table 3 shows the failure rate for each valve type. It is calculated using an exposure denominator of the number of installed valves multiplied by the number of tests required annually. The exposure denominator differs for valve types, due to differing numbers of installations and required testing frequencies.

In 2019, approximately 11,849 SPPE valves were in service in 5,335 active wells in the GOM OCS. The total GOM SPPE failure rate is 0.28 percent, as compared to the 2018 rate of 0.24 percent calculated under the revised method. The failure rates for each SPPE valve type (except SSCSVs) span from 0.07 percent for USVs to 0.67 percent for GLSDVs. The failure rate for SSCSVs spans from 0.44 percent to 0.88 percent, depending on the required testing frequency. The low failure rate for USVs may be explained by the lower testing frequency (quarterly) and the higher allowable leakage rate (see Table 1). For SSCSVs, low and high exposure denominators were used to account for the differing testing requirements for SSCSVs not installed in landing nipples (tested every six months) versus those installed in landing nipples (tested every 12 months). The range of failure rates for SSCSVs reflects a limitation of the analysis that could be addressed through additional evaluation of SSCSV test data, as discussed under the *Next Steps* section. However, even at the low end of its failure rate range (0.44 percent), SSCSVs have a higher failure rate than other valve types except for GLSDVs. A higher relative failure rate for SSCSVs is reflective of known reliability issues, as seen in BSEE's decision to no longer allow these valve types in new subsea wells (see SPPE Valve Types discussion on page 8).

The higher failure frequency for the GLSDVs (0.67 percent) is likely an artifact of the low count in the GOM. It has the lowest exposure denominator among the SPPE valve type, 300, compared to a range of 1,138 to 65,664 for other valve types. With a low number of installed valves, each failure contributes a higher percentage to the GLSDV failure rate, relative to each failure for other SPPE valve types.

SSVs and SCSSVs have the highest numbers of installations, totaling over 10,000 compared to less than 1,500 for other SPPE valve types combined. Although SSVs have the highest number and proportion of reported failures, SCSSVs have a higher failure rate (0.39 percent) after adjusting for required testing frequency.

Table 3: SPPE Failure Rates in the Gulf of Mexico in 2019

Valve Type	Reported Failures	Installed Valves	Annual Testing Frequency	Exposure Denominator*	Failure Rate†
SSV	172 (76.4%)	5,472	Monthly (12/yr.)	65,664	0.26%
SCSSV	39 (17.3%)	4,940	Semiannually (2/yr.)	9,880	0.39%
SSCSV	5 (2.2%)	569	1 or 2/yr.‡	569 – 1,138	0.44% – 0.88%
BSDV	5 (2.2%)	174	Monthly (12/yr.)	2,088	0.24%
USV	2 (0.9%)	669	Quarterly (4/yr.)	2,676	0.07%
GLSDV	2 (0.9%)	25	Monthly (12/yr.)	300	0.67%
All Valves	*225 (100%)*	*11,849*	*N/A*	*81,462*	*0.28%*

NOTE:

* Installed valves multiplied by annual testing frequency. In the total, an average value is used for SSCSVs ((569 + 1,138) / 2).

† Reported failures divided by exposure denominator.

‡ SSCSVs must be tested semiannually, not to exceed 6 months between tests for valves not installed in a landing nipple and 12 months for valves installed in a landing nipple.

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

Failures and Potential Consequences

To put SPPE failures in perspective, one must consider the potential consequences of such failures based on the extent to which they degrade the installed well safety systems and potential consequences to personnel and the environment. Failure events were categorized as an external leak, failure to close, internal leak, and failure to open, as seen in Table 4. Further, the reported events could include more than one type of failure (e.g., both failed to close and internal leak). Nine of the 225 reported failures involved two failure types, with the remainder involving a single failure type. Failure events were further categorized based on whether they took place on the platform (SSV, BSDV, and GLSDV) or away from the platform (SCSSV, SSCSV, and USV), as seen in Figure 7.

BTS reclassified some failure to close events as internal leakage when it could be confirmed that the failure type was in fact internal leakage and not failure to close. For cases where no leakage rates were provided, BTS deferred to the operator's reported event type of failure to close. BTS will consider clarifying failure to close in a future form revision to ensure it is captured accurately.

Of the 225 failure reports, the majority (79.6 percent) occurred on the platform (SSVs, BSDVs, and GLSDVs - Figure 1) rather than in the wellbore tubing or below sea level. Most of the on-platform failures were SSV failures (172 or 76.4 percent). Four SSV failures were associated with two failure event types, for a total of 176 failure types for all reported SSV failures. The majority of SSV failures were categorized as internal leaks (159 or 90.3 percent), 10 as external leaks (5.7 percent), five as failed to close (2.8 percent), and two as failed to open (1.1 percent). Three BSDV failures were internal leaks and two were reported as a failure to close. The reported GLSDV failures were both internal leaks.

SCSSVs accounted for most of the events away from the platform, comprising 39 (17.3 percent) of the reported failures. Five SCSSV failures were associated with two failure event types, for a total of 44 failure types for all reported SCSSV failures. Nearly one-third (14 of 49 or 28.6 percent) of subsurface safety valve (SCSSV and SSCSV) failures, when categorized by type, were due to failure of the valve to close, as compared to 48.6 percent in 2018. The remaining failures of subsurface safety valves, when categorized by type, were internal leaks (33 or 67.3 percent) and failure to open (2 or 4.1 percent). Two USV failures were reported to SafeOCS for the first time in 2019, and both were internal leaks.

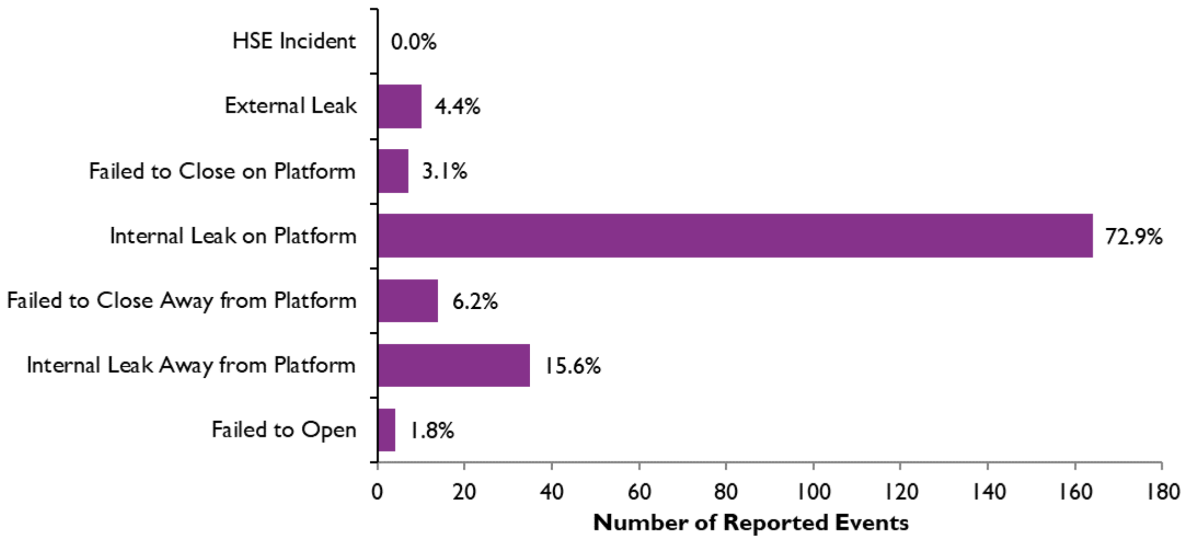
The types of failures are described below in order of significance, based on the extent of degradation of installed well safety systems and potential consequence to personnel and the environment. Their frequency is illustrated in Figure 7 and broken down further by the SPPE valve type in Table 4.

- **HSE Incident**: None of the reported failures were associated with a health, safety, and environment (HSE) incident. (See Appendix F for more information on what constitutes an HSE incident).
- **External Leak**: The most significant type of failure reported is an external leak (i.e., loss of primary containment), where fluids could leak into the environment. Most of the external leaks were hydraulic fluids leaking from an SSV component (e.g., from a hole in the bladder of the valve's actuator). In most cases, the hydraulic fluids used in these safety systems have been determined to pose a low environmental risk and do not represent a danger to personnel or marine life. Occasionally, a more significant external leak may be found where well fluids (oil and/or gas) could leak from the well directly. Ten such (10) failures were reported:

  - Four (4) failures were considered a loss of primary containment of well fluids, where a small amount of well fluids leaked from SSVs to the atmosphere. The leaks were not significant enough to be considered HSE incidents (see Appendix F).
  - Six (6) external leaks were leaks of control fluid (instrument air, instrument gas, or hydraulic fluid) from the valve's actuator. If these actuator failures had worsened, the SSV is designed to close (fail-safe) and stop the flow of fluids from the well, resulting in a safe condition.

- **Failure to Close, on Platform**: The second most significant type of failure reported was an SPPE valve *on the platform* failing to close, which means that the SPPE valve would not be effective in controlling the well flow if called upon. Seven (7) such failures were reported.
- **Internal Leak, on Platform**: The third most significant type of SPPE failure reported was SPPE valves *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. One hundred sixty-five (165) such failures were reported.
- **Failure to Close, Away from Platform**: The fourth most significant type of failure reported was SPPE valves *away from the platform* (subsea or in the well) failing to close, which means that SPPE valves would not be effective in controlling the well flow if called upon. Fourteen (14) such failures were reported.
- **Internal Leak, Away from Platform**: The fifth level of significance is an internal leak of an SPPE valve *away from the platform* (subsea or in the well) where the internal leakage rate exceeded the allowable leakage rate. Thirty-four (34) such failures were reported.
- **Failure to Open**: The sixth level of significance is a failure to open, either on the platform or away from the platform. A failure to open means that well fluids would not flow through the tubing. In cases of failure to open, the valve is still capable of performing its safety function of controlling the well flow. Four (4) such failures were reported.

Figure 7: Type of Reported Failure Events in Order of Significance



NOTE: More than one type of reported event could occur within a single reported failure.

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

Table 4: Type of Reported Failure Events by Type of Valve

	On Platform			Away from Platform		
Type of Failure	**SSV**	**BSDV**	**GLSDV**	**SCSSV**	**SSCSV**	**USV**
External Leak	10	0	0	0	0	0
Failed to Close	5	2	0	9	5	0
Internal Leak	160	3	2	31	1	2
Failed to Open	2	0	0	2	0	0

NOTE: More than one type of reported event could occur within a single reported failure.

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

Well Location and Production

Shallow Water Province versus Deepwater

Many wells are located in the GOM shallow water province, which BSEE defines as the portion of the OCS with water depths of 200 meters (656 feet) or less.[19] As shown in Table 5, most active wells (82.1 percent) are within the shallow water province, and most SPPE failures (88.1 percent) were associated with shallow water wells. To facilitate comparison across water depth groups, the proportion of SPPE

[19] Bureau of Safety and Environmental Enforcement and Bureau of Ocean Energy Management, Information/Briefing Report: Gulf of Mexico Data and Analysis/ Leasing, Drilling and Production; Gulf of Mexico Shallow Water Potential Stranded Assets, Nov. 19, 2019, https://www.bsee.gov/sites/bsee.gov/files/reports/shallow-water-report-01.pdf.

failures for each group was evaluated against an expected proportion of failures equal to one (indicating an expected equal likelihood of failure across groups). The "Actual to Expected Failure Ratio" is calculated by dividing the percentage of SPPE failures by the percentage of active wells in each group. A number higher than one indicates a greater proportion of failures than expected in that group, while a number less than one indicates a lower proportion than expected. Wells of water depth up to 800 meters had about the expected proportion of reported SPPE failures. Wells of water depth greater than 800 meters had a lower than the expected proportion of reported SPPE failures.

Table 5: Distribution of SPPE Failures by Water Depth

Water Depth (m)	Number of 2019 SPPE Failures	Number of Active Wells	Actual to Expected Failure Ratio
< 200	192 (88.1%)	4382 (82.1%)	1.07
200 - 800	17 (7.8%)	353 (6.6%)	1.18
> 800	9 (4.1%)	600 (11.2%)	0.37
Not Reported	7	-	N/A
Total	*218 (100.0%)**	*5335 (100.0%)*	*N/A*

NOTE: *Total (218) excludes the seven failures for which water depth was not reported.

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

Well Rate Range

Operators are responsible for measuring the well production rates of oil, gas, and water for all producing wells on the OCS. To do this, operators perform periodic well tests to calculate the daily fluid volumes produced from each well in barrels of oil and water and standard cubic feet of gas, or "well rate" (see the Well Test and Well Rate section of Appendix D). Depending on the well, the well rate can range from less than one BOE/day to over 10,000 BOE/day. The risk of adverse environmental consequences or production interruptions associated with a failure increases proportionally to the well rate because the potential rate of the released volume is higher for wells with higher well test rates.

Table 6 shows the SPPE failures grouped by well rate range using the average daily production from the well near the time of the failure. The table also compares the failures with the well rate of all active wells in the GOM OCS. Most of the failures (86.2 percent) were associated with wells that produce less than 500 BOE/day, with more than half (55.5 percent) producing less than 100 BOE/day. These wells pose a lower risk than higher-producing wells. Less than 1.0 percent of the reported failures were associated with wells producing more than 5,000 BOE/day.

The average daily production rates shown in Table 6 can offer insight into the potential environmental exposure of the 225 failures. The total daily production volume from the wells that experienced an SPPE failure in 2019 was 68,186 BOE/day. Comparing this figure to the average daily production from the GOM OCS in 2019 (2,741,291 BOE/day) indicates that only 2.5 percent of the GOM OCS production could have been directly affected by the 225 reported SPPE failures.

To facilitate comparison across groups, the proportion of SPPE failures for each well rate group was evaluated against an expected proportion of failures equal to one (indicating an expected equal likelihood of failure across groups). The "Actual to Expected Failure Ratio" is calculated by dividing the percentage of SPPE failures by the percentage of active wells in each group. A number greater than one indicates a greater proportion of failures than expected in that group, while a number less than one indicates a lower proportion than expected. For both the number of wells and average daily production, wells that produced between 100-499 and 500-999 BOE/day had the highest actual to expected failure ratios. In general, the actual to expected failure ratios show that a disproportionately high number of the reported SPPE failures occurred on the lower rate wells.

Along with the nature of the failure, the well's production rate is important in evaluating the potential environmental impact. Figure 8 shows that the higher producing wells (greater than 1,000 BOE/day) had no external leaks or failures to close on the platform, the most significant types of reported failures. Wells that produced between 500-999 BOE/day had two external leak events, and wells that produced between 100-499 BOE/day had three external leak events. Two of these five external leak events are considered losses of primary containment of well fluids, where a small amount of well fluids leaked from the SSV to the atmosphere.

Table 6: SPPE Failures and Active Wells by Well Rate Range

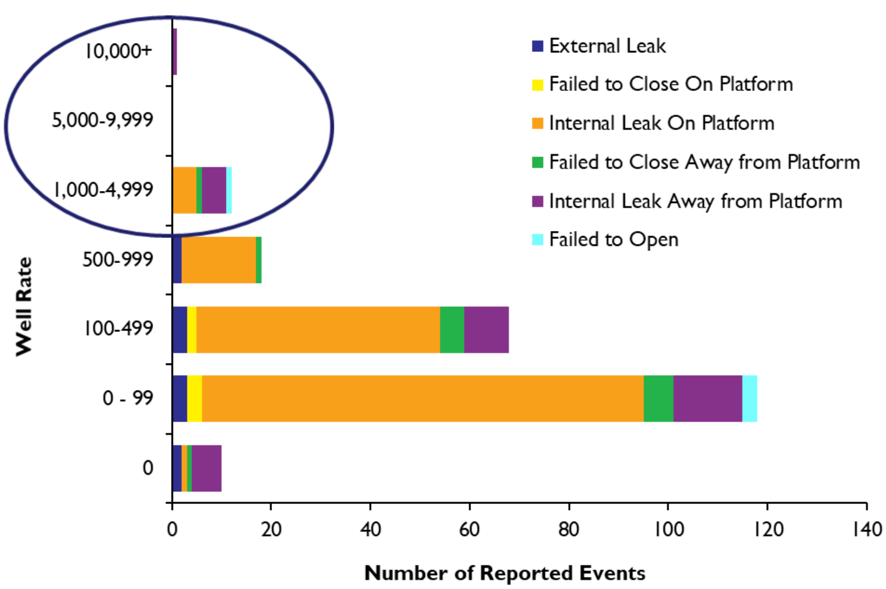
Well Rate Range	Number of Wells			Average Daily Production		
	Wells with SPPE Failure	Active Wells	Actual to Expected Failure Ratio	Wells with SPPE Failure	Active Wells	Actual to Expected Failure Ratio
0	10 (4.6%)	2,128 (39.9%)	0.12	0 (0.0%)	0 (0.0%)	0.00
<100	111 (50.9%)	1,818 (34.1%)	1.49	4,975 (7.3%)	69,138 (2.5%)	2.89
100-499	67 (30.7%)	763 (14.3%)	2.15	15,891 (23.3%)	158,924 (5.8%)	4.02
500-999	18 (8.3%)	195 (3.7%)	2.26	13,287 (19.5%)	139,758 (5.1%)	3.82
1,000-4,999	11 (5.0%)	251 (4.7%)	1.07	23,824 (34.9%)	627,228 (22.9%)	1.53
5,000-9,999	0 (0.0%)	113 (2.1%)	0.00	0 (0.0%)	798,993 (29.1%)	0.00
>10,000	1 (0.5%)	67 (1.3%)	0.37	10,209 (15.0%)	947,249 (34.6%)	0.43
Not Reported	7	-	N/A	-	-	N/A
Total	*218 (100.0%)**	*5,335 (100.0%)*	*N/A*	*68,186 (100.0%)*	*2,741,291 (100.0%)*	*N/A*

NOTE:

1. *Total (218) excludes the seven failures for which well rate was not reported.
2. Well rate and total daily production units are BOE/day. Ratio = % of SPPE Failures / % of Active Wells.

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

Figure 8: Type of Reported Failure by Well Rate Range



NOTE: Well rate units are BOE/day. Type of reported failure is in order of significance in the legend. More than one nature of reported event could occur within a single reported failure.

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

Water Cut Range

A well's water cut is its ratio of water volume produced to the total liquid volume (oil plus water).[20] Higher water cut can be associated with sand production,[21] which can damage SPPE valves. In Table 7, wells are grouped by water cut ranges. As with well rate, an "Actual to Expected Failure Ratio" is shown in Table 7 and was calculated by dividing the percentage of SPPE failures by the percentage of active wells in each group. A number higher than one indicates a greater proportion of failures than expected in that group, while a number less than one indicates a lower proportion than expected. This ratio shows that a disproportionately higher number of reported failures occurred in wells with zero percent or greater than 90 percent water cut.

Regarding the latter group (greater than 90 percent water cut), high water cut wells typically produce more sand than wells with low water cuts due to the higher pressure drops associated with water moving through the reservoir formation (compared to oil). This characteristic could result in more sand flowing through the SPPE valves (SSVs and SCSSVs), which can be erosive and cause premature valve failure.

Of the 18 failures in the zero percent water cut group, 6 (33.3 percent) were associated with gas wells, which typically produce at low water cuts. Gas production with even small amounts of sand is even more erosive that water with sand, which could contribute to a higher number of failures in this group.

SPPE failure notifications were reviewed to evaluate how often sand was reported as present at the time of the failure. Sand was mentioned in failure notifications for seven of 49 events (14.3 percent) in the *greater than 90 percent* water cut group and one of 18 events (5.6 percent) in the *zero percent* water cut group. This topic is addressed further in the discussion of contaminants below.

[20] Adapted from Schlumberger Oilfield Glossary, https://www.glossary.oilfield.slb.com.

[21] See, e.g., Wu et al., Effect of Water-Cut on Sand Production – An Experimental Study, *SPE Production & Operations*, 2006, 21(3): 349-356.

Table 7: SPPE Failures and Active Wells by Water Cut Range

Water Cut Range	SPPE Failures	Active Wells	Actual to Expected Failure Ratio
No Production	10 (4.6%)	2,128 (39.9%)	0.12
0%	18 (8.3%)	191 (3.6%)	2.31
0-10%	9 (4.1%)	513 (9.6%)	0.43
10-50%	62 (28.4%)	964 (18.1%)	1.57
50-90%	70 (32.1%)	1,076 (20.2%)	1.59
>90%	49 (22.5%)	463 (8.7%)	2.59
Not Reported	7	-	N/A
Total	*218 (100%)**	*5,335 (100%)*	*N/A*

NOTE:

1. *Total (218) excludes the seven failures for which water cut was not reported.
2. Water cut = water produced / total liquids produced. Ratio = % of SPPE Failures / % of Active Wells.

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

Contaminants

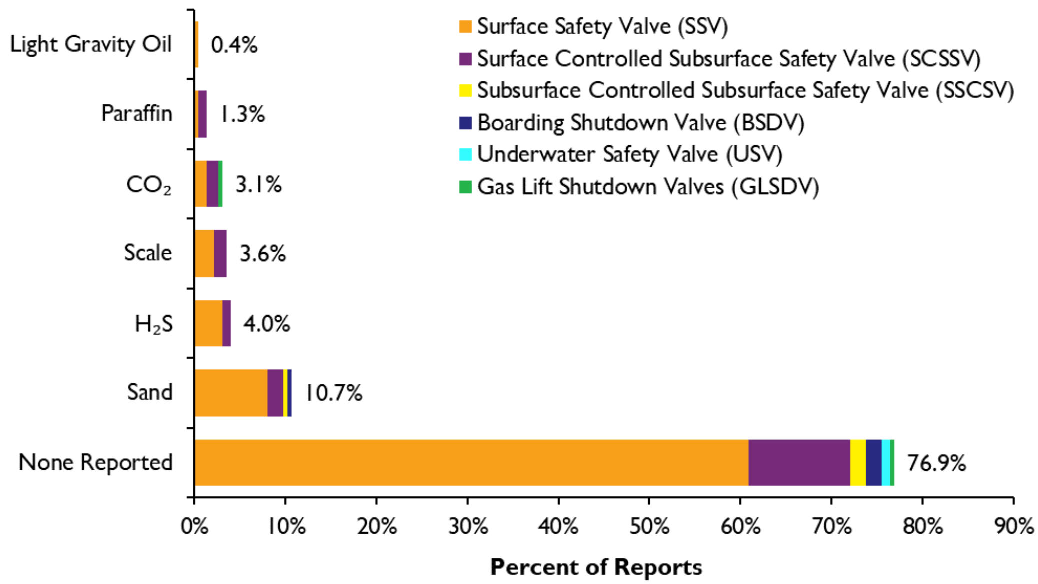
In addition to producing oil, gas, and water, production wells may contain unfavorable contaminants in the well stream, such as sand, hydrogen sulfide (H_2S) and carbon dioxide (CO_2). Figure 9 shows these and other reported contaminants or well fluid characteristics, including scale build-up, paraffin, and light gravity oil. At least one of these was reported for 46 of 225 failures (20.4 percent).

As discussed above, well fluids can carry solids such as sand through the tree's valves during production. The presence of sand can cause mechanical damage by eroding the equipment and plugging components within the production equipment. The 24 failure reports (10.7 percent) indicating sand present in the wells included 18 SSV failures. Some valves are designed with the expectation of sand or other contaminants in the flow stream (Class 2, see Appendix G). Of the 24 SPPEs indicating sand present, eight were designated as Class 2, and five were Class 1 valves for service in normal operating conditions (i.e., not for sand exposure). The classification was not provided for the remaining valves.

Some wells naturally contain H_2S or CO_2, both of which can lead to corrosion damage to the equipment. Sixteen failure reports (7.1 percent) indicated the presence of H_2S, CO_2, or both. Of the nine failure reports indicating the presence of H_2S, seven were associated with SSV failures and two were SCSSV failures. Of the seven failure reports indicating the presence of CO_2, three were associated with SSV failures, three were SCSSV failures, and one was a GLSDV failure.

Even though there were well stream contaminants present, they may not have been the cause of the failure. The next section contains more information on failure causes. Over three quarters (79.6 percent) of the reports did not indicate any contaminants present in the well stream. BTS will consider how to capture better contaminant information in a future form revision.

Figure 9: Well Stream Contaminants



NOTE: Reporting operators may select more than one contaminant.

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

What Factors Contributed to Failures

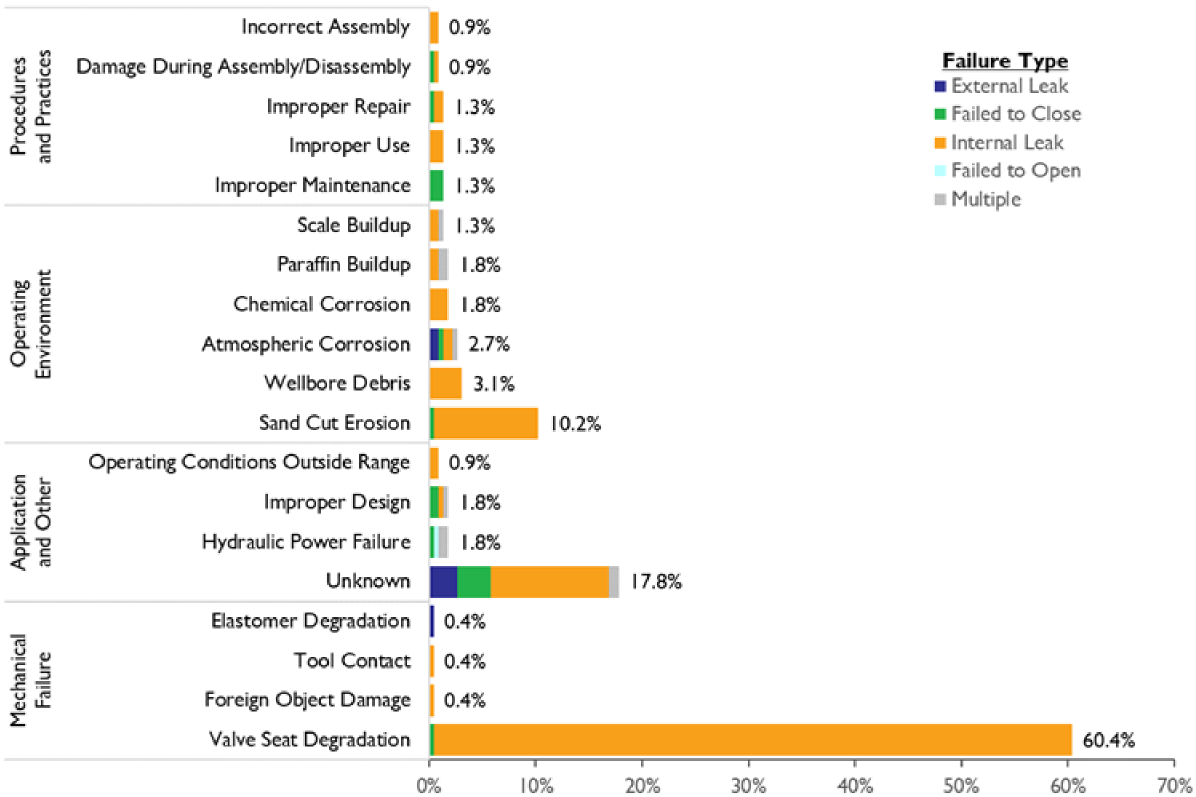
Operators were asked to report all contributing factors associated with a failure. Failure reports, including failure narratives, were also qualitatively analyzed to determine the factors contributing to the reported failure. Figure 10 shows the results. The colored bars indicate the portion of each category that involved a leak (internal or external) versus other failure types (failure to open or close). As shown in Figure 7, most reported failure types were leaks, with internal leaks making up 88.4 percent of failure events. External leaks made up 4.4 percent. This finding provides context for the following observations.

Valve seat degradation was the most commonly reported contributing factor, reported for 60.4 percent of failure events. This is expected since valve gates or seats were the most commonly reported failed component. Factors related to the operating environment—sand cut erosion, atmospheric or chemical corrosion, paraffin, debris, and scale—were designated as contributing factors in 20.9 percent of reports. Sand cut erosion made up most of these (10.2 percent). *Sand cut erosion* was designated when sand contaminants degraded the SPPE valve. 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.

Of the three cases categorized as *improper maintenance*, all were categorized as failures to close. As discussed above (see Failures and Potential Consequences, page 23), some reporters may select "failed to close" in cases of a test that exceeds the allowable leakage rate; therefore, cases in which *improper maintenance* was a contributing factor could involve leaks. The same observation may be true for other contributing factors for events categorized as failure to close, such as *improper repair*. As stated above, BTS will consider clarifying this failure type category in a future form revision.

On the SafeOCS SPPE Failure Notification Form, operators select from a list of contributing factors or choose "other" and provide a description. In analyzing 2019 failure events, SafeOCS reclassified four of the listed contributing factors to failure types, as discussed in Failures and Potential Consequences (page 23): *mechanical failure – leak*, *failed to open*, *failed to close*, and *failed to contain hydrocarbons*. Figure 10 shows the failure types within each contributing factor. Events with more than one failure type are labelled as "Multiple." BTS will consider how to better distinguish between contributing factors and failure types in a future form revision.

Figure 10: Factors Contributing to Equipment Failures



NOTE: Reporters could choose more than one contributing factor, resulting in a total greater than 100 percent.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

How Failures Were Detected

SPPE failures can be detected in several ways, for example, during testing, while the equipment is undergoing normal operation, or when production halts (is shut-in) due to abnormal or emergency conditions. Most of the reported failures (87.1 percent) were found during routine leakage tests (see Figure 11). Twenty-eight failures (12.4 percent) were found during normal well operations, and leakage testing was also selected as the operating condition at the time of failure for nearly 40 percent of these (11 failures).

Examination of the 12 failures (5.3 percent) found during an emergency shutdown (ESD) response showed that all of these occurred during ESD testing rather than during an emergency event. BTS will consider clarifying this activation condition category in a future form revision. One failure (0.4 percent) was reported as detected through an emergency condition. In this case, the failure was detected after bringing a well back online following a shut-in for hurricane evacuation.

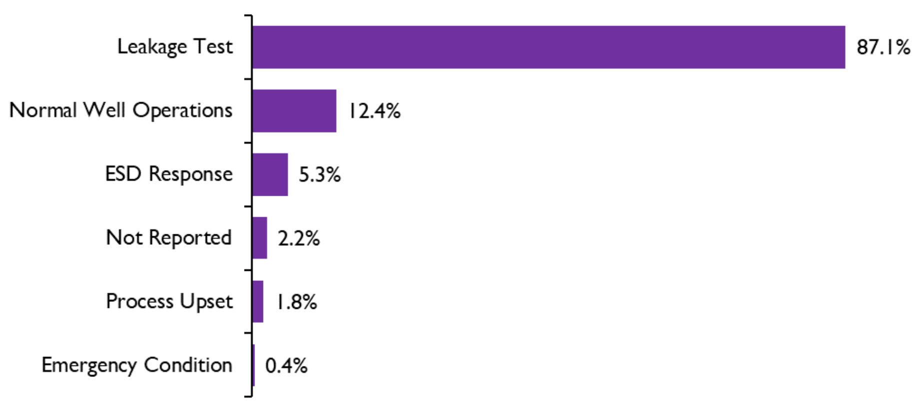
Four failures (1.8 percent) were detected through a process upset (disruption from steady operations):

- One (1) involved an SPPE failure found after bringing a well back online following a shut-in for pipeline repair;
- Two (2) involved SPPE failures detected through control room monitoring that showed tubing pressure increasing while the well was shut-in; and
- One (1) did not provide enough information to determine the nature of the process upset.

The operating condition at the time of the failure was not reported for five failures (2.2 percent).

When a failure is found, the well must be shut-in until the appropriate corrective actions have been taken to address 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. Although 63.1 percent of the failure reports indicated that the well was shut-in when the failure occurred, evaluation of OGOR-A data showed that only ten failure reports (4.4 percent) were associated with wells in shut-in status during the month the failure occurred. This difference may be due to the unclear meaning of the question on the SafeOCS form, and BTS will consider clarifying this question in a future form enhancement.

Figure 11: Failure Detection Methods



KEY: ESD—Emergency shutdown.

NOTES:

1. Reporters could choose more than one method of detection.
2. All failures detected during ESD response occurred during ESD testing rather than during an emergency event.
3. One failure (0.4%) was reported as detected through an emergency condition. In this case, the failure was detected after bringing a well back online following shut-in for hurricane evacuation.

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

How Failures Were Addressed

Failure reports described corrective actions taken to address the failure (see Figure 12), ranging from component servicing to repair or replacement. For example, some 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. In some cases, multiple actions were taken to address the failure, e.g., testing to locate the failed valve, inspecting the valve to pinpoint the issue, servicing the valve, and retesting. In those cases, the most significant corrective action, i.e., the corrective action requiring the highest level of intervention, is represented in Figure 12.

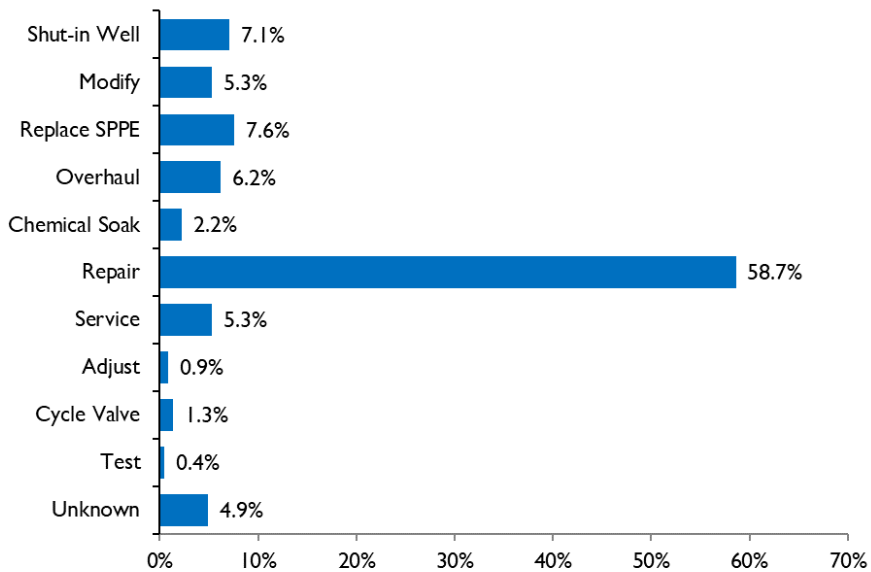
The same types of corrective actions were sometimes reported differently. For example, a repair may have been reported as *repair*, *replace* (often when only part of the valve was replaced), or in some cases another action such as *overhaul* or *service*. BTS will consider clarifying the meanings of corrective action terms in a future form revision. To improve the accuracy and uniformity of the corrective action data in evaluating the 2019 reported failure events, failure reports, including failure narratives, were qualitatively analyzed to determine corrective actions and employed the following informal definitions for select terms shown in Figure 12 and Figure 16.

- *Shut-in Well* – the well was shut-in, meaning valves were closed to halt flow from the well, either permanently or until remediation can be performed.
- *Modify* – a change was made to the valve (e.g., replacing it with a different model or type) or to the well (e.g., setting a tubing plug).
- *Replace SPPE* – the entire valve was replaced with the same valve type.
- *Remanufacture* – the valve was rebuilt by the manufacturer using restored, repaired, or new parts.
- *Overhaul* – actions were taken that involve a significant scope of work beyond servicing or repair (e.g., specialized diagnostics, complete disassembly, specialized repair procedure, and reassembly) to restore the valve to fully serviceable condition.
- *Chemical Soak* – a chemical solvent was introduced to the valve to dissolve buildups of contaminants such as scale.
- *Repair* – the valve was repaired, or part of the valve (i.e., a component) was replaced.
- *Service* – maintenance was performed on the valve (e.g., greasing).
- *Adjust* – maintenance was performed that involved fine-tuning the valve or operation settings.
- *Cycle Valve* – the valve was stroked, meaning it was moved from its fully open position to its fully closed position and back to open fully.

- *Test* – the valve was tested.
- *Unknown* – the reporter did not provide information about any corrective actions taken.

Repair was the most commonly reported most significant corrective action, reported for 58.7 percent of events. *Repair* events were further classified based on the type of component repaired (Figure 13) to gain more insight into the corrective action taken. As expected, based on reported component failures, the most commonly repaired component was the valve gate or seat, which comprised 85.6 percent of repairs. Often, not enough information is provided in a failure notification to determine the nature of the repair. BTS will consider changes to the data collection form to collect better information regarding repair actions.

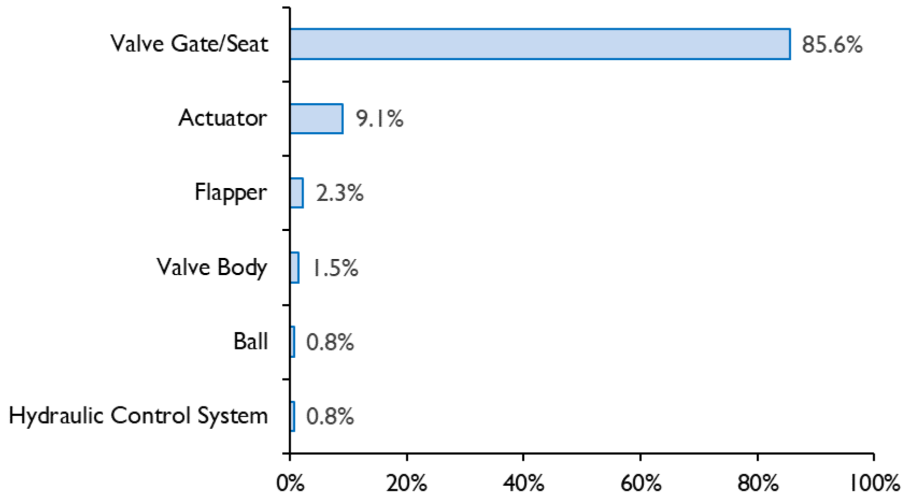
Figure 12: Reported Corrective Actions



NOTE: Corrective actions are listed from higher to lower degree of intervention. If multiple corrective actions were reported for an event, the action with the greatest degree of intervention is shown.

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

Figure 13: SPPE Components Repaired



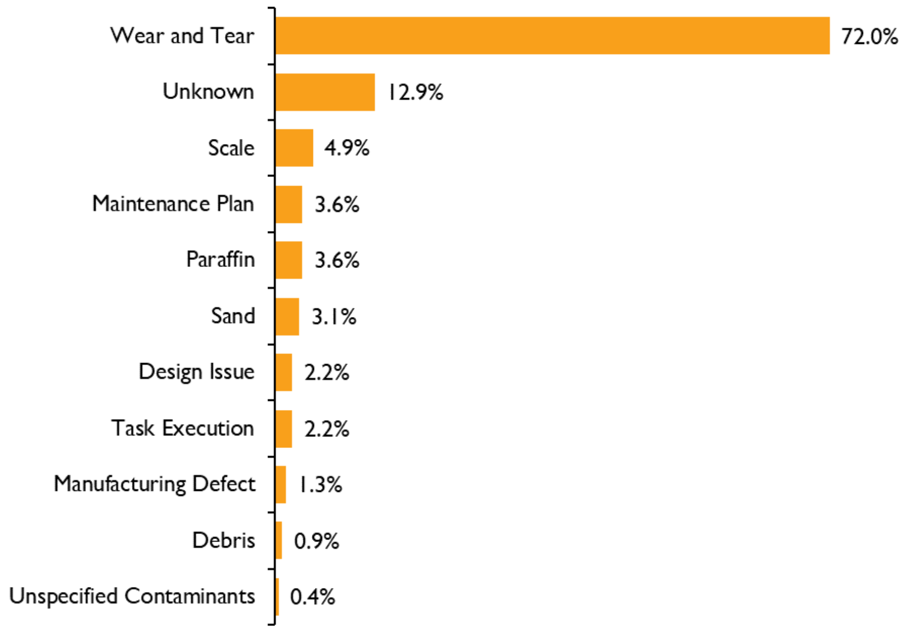
NOTE: The chart represents 132 of 225 failure events in which *repair* was the most significant corrective action taken.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

Root Causes of Failures

Operators identified and reported the suspected root cause of the failure (Figure 14). *Wear and tear* was the most commonly reported root cause, reported for 162 of 225 failures (72.0 percent). Scale build-up was identified as a root cause for 4.9 percent of reported failures. Together, contaminants—including scale, sand, paraffin, debris, and unspecified contaminants—were determined as a root cause for 12.9 percent of reported failures. For 12.9 percent of reported failures, there was not sufficient information to determine a root cause.

Furthermore, on wear and tear, SSVs make up most wear and tear failures (144 out of 162, or 88.9 percent). In 12 of the 162 failures (7.4 percent) in which *wear and tear* was reported as a root cause, a second root cause was also reported: *scale* (6 failures), *sand* (3 failures), *design issue* (1 failure), *task execution* (1 failure), or *manufacturing defect* (1 failure). Several analyses, discussed below, were performed to gain more insight into the nature of wear and tear failures, given their sizeable proportion of the failure reports.

Figure 14: Root Causes of Reported Failure Events

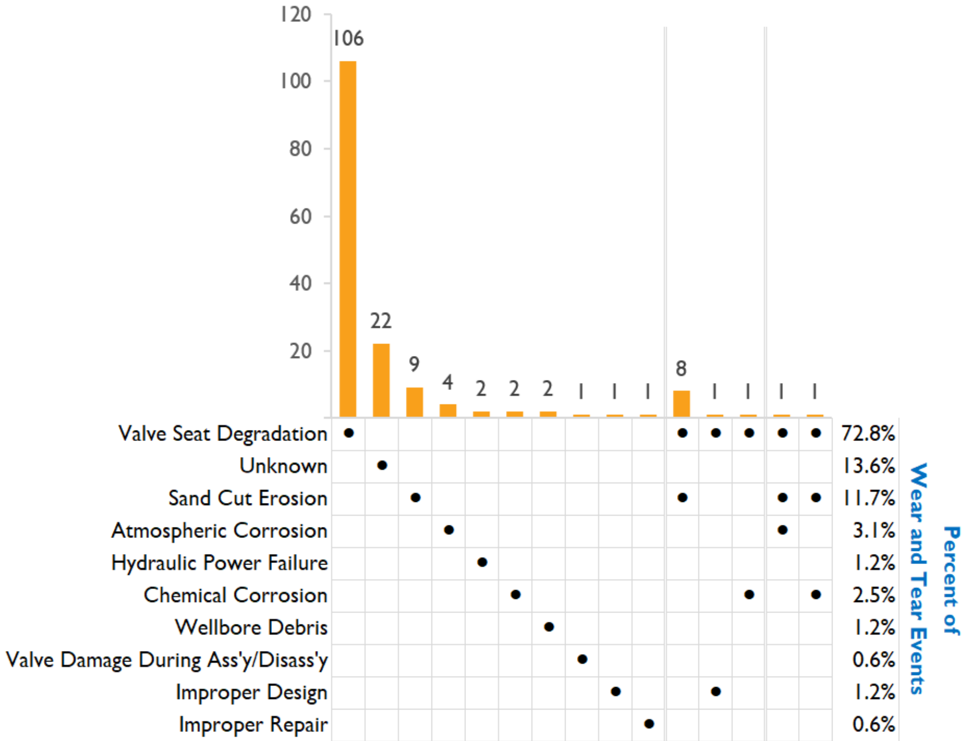


NOTE: Reporters could choose more than one suspected root cause, resulting in a total greater than 100 percent.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

Contributing Factors to Wear and Tear Events

Wear and tear was reported as a root cause for almost every nature of failure; however, several contributing factors were reported more commonly than others. In Figure 15, each column shows the count of wear and tear failure events with each reported combination of contributing factors, marked with dots. Among 162 wear and tear failures, valve seat degradation was reported for 118 (72.8 percent). Erosion (sand) or corrosion (chemical or atmospheric) was designated as a contributing factor in 17.3 percent of wear and tear failures, with sand cut erosion making up most of these (11.7 percent). These figures align with the results for all SPPE failures, discussed above under Shallow Water Province versus Deepwater (page 31).

Figure 15: Factors Contributing to Wear and Tear Failures



KEY: ass'y/disass'y—assembly/disassembly.

NOTES:

1. Bar value indicates the number of wear and tear failures reported with the dotted contributing factor combinations. The vertical lines separate events with one reported factor (left) from those with two (center) and three (right).
2. Percent values indicate proportion of 162 wear and tear events with the listed contributing factor. The percentages total greater than 100 because reporters could choose multiple contributing factors.

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

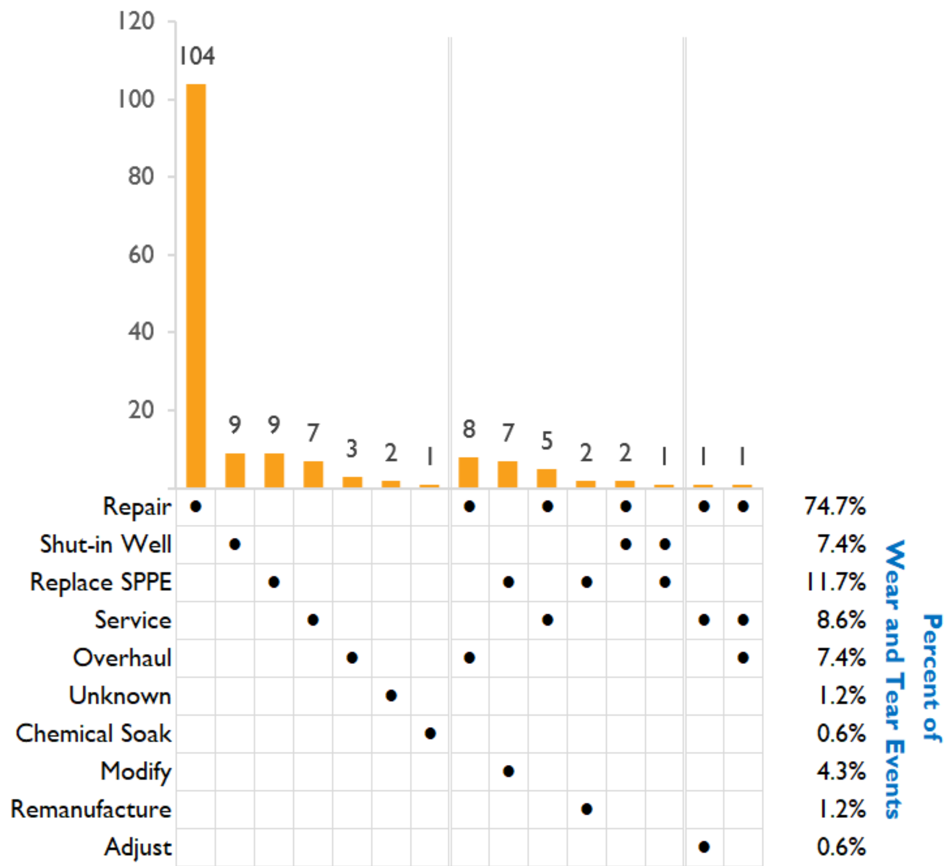
Corrective Actions for Wear and Tear Events

In Figure 16, each column shows the number of wear and tear failure events with each reported combination of corrective actions, marked with dots. The most common corrective action for wear and tear failures was *repair*, reported for 121 of 162 (74.7 percent) wear and tear failures. The entire valve was replaced in 19 of 162 (11.7 percent) wear and tear failures.

Repair was the sole corrective action reported in 104 of 162 (64.2 percent) wear and tear failures. It was reported with a combination of *overhaul*, *service*, *shut-in well, or adjust* for an additional 17 wear and tear failures, totaling 121. Among 27 wear and tear failures with multiple corrective actions, the most commonly reported combination of corrective actions was *repair* and *overhaul* (eight failure events), followed by *modify* and *replace SPPE* (seven failure events).

Figure 17 shows the components involved in repairs. As expected, based on reported component failures, the most commonly repaired component was the valve gate or seat, which comprised 88.4 percent of repairs for wear and tear failures. Actuators were the next most commonly repaired component, comprising 7.4 percent of repairs for wear and tear failures. As discussed above, often, not enough information is provided in a failure notification to determine the nature of the repair. BTS will consider changes to the data collection form to collect better information regarding repair actions.

Figure 16: How Wear and Tear Failures Were Addressed

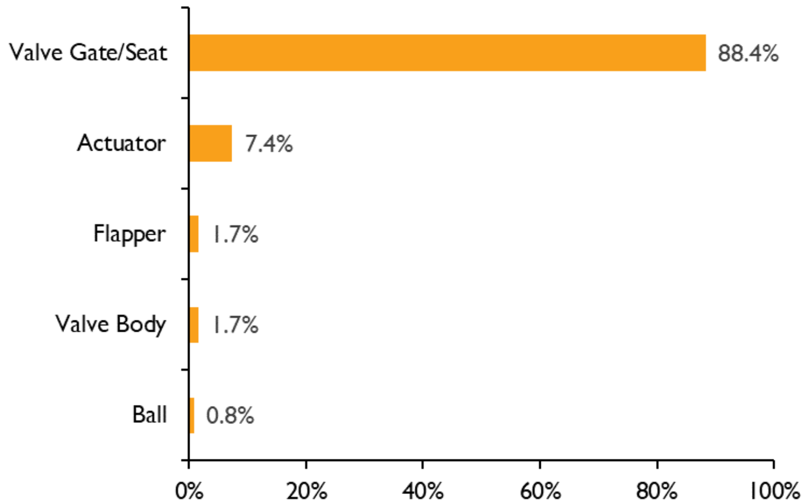


NOTES:

1. Bar value indicates the number of wear and tear failures reported with the dotted corrective action combinations. The vertical lines separate events with one reported corrective action (left) from those with two (center) and three (right).
2. Responses coded as *test*, *check*, or *inspection* are excluded because these actions are typically taken for any failure.
3. Percent values indicate proportion of 162 wear and tear events with the listed corrective action. The percentages total greater than 100 because reporters could choose multiple corrective actions.

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

Figure 17: SPPE Components Repaired in Wear and Tear Failures



NOTE: The chart represents 121 wear and tear failures corrected by repair.

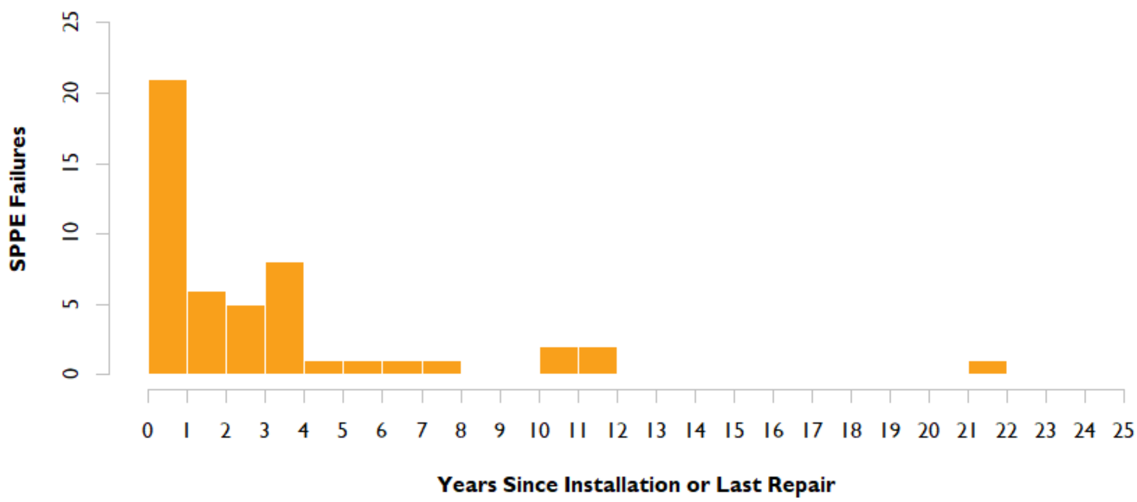
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

Time to Failure for Wear and Tear Events

To further explore what constitutes normal wear and tear, an analysis of SPPE time to failure was performed. The SafeOCS SPPE Failure Notification Form does not currently include a field for the installation date. For 49 of 162 wear and tear failures, the reporter provided either the date of installation or date of last repair in the narrative description or the redress history. The reported dates of installation or last repair ranged from less than one year to greater than 20 years, as shown in Figure 18. For 40.8 percent of these failures (20 of 49), the valve failed within one year of installation or last repair. For nearly two-thirds (31 of 49, or 63.3 percent), the valve failed within three years. The 49 valves comprised 47 SSVs, one SCSSV, and one SSCSV. The two subsurface safety valves fall within the 0 - 1 year group in Figure 18.

As the SPPE valves are critically important to the safe production of oil and gas in the OCS environment, operators are strongly encouraged to include as much detail as possible on the SafeOCS SPPE Failure Notification Form so that a more thorough evaluation of each failure can be conducted. BTS will consider changes to better capture this information in a future form enhancement. Such improvements will facilitate analysis and understanding of SPPE reliability.

Figure 18: Time to Failure for Wear and Tear Events



NOTE: Date of installation or last repair was reported for 49 of 162 wear and tear failures.

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

Repeated Failures

In 14 cases (13 SSVs and 1 SCSSV), the same component on the same SPPE failed more than once during 2019. Two reported SSVs had three repeated failures, and another 11 SSVs had two repeated failures within the year.

A third of reporting operators (five) reported repeated failures. Table 8 shows the number of reported SSV failures among the five operators and the proportion that are repeated failures. In total, 171 failures were reported for 156 SSVs. Of the 156 SSVs, 13 (8.3 percent) failed two or three times in 2019. All of the 28 SSV repeated failures were internal leaks, and one of the SSV failures also indicated an external leak of instrument gas from the valve actuator. Most of the repeated failures (23 of 28) resulted in repair or servicing of the valve, and five failures resulted in valve replacement. Eleven valves experienced two failures during 2019, and two valves experienced three failures each during 2019.

Table 8: SSVs with Multiple Reported Failures in 2019

Operator	SSVs with... 1 Failure	2 Failures	3 Failures	Percentage of SSVs with Repeated Failures
aa	69	5	1	8.0%
bb	35	4	0	10.3%
cc	28	1	0	3.4%
dd	4	1	0	20.0%
ee	2	0	1	33.3%
Others	5	0	0	0.0%
Total	*143*	*11*	2	*8.3%*

NOTE: SafeOCS does not disclose operator names to preserve reporter confidentiality.

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

The SCSSV repeated failure was a case of exceeding the internal leakage rate on two consecutive semi-annual tests. The corrective action on the first failure was a chemical soak of the valve. After the second failure, the valve was replaced.

The failed valves were of various manufacturers, models, pressure ratings, sizes, and classes. All the repeat failures were detected during leakage testing. Twelve failure reports indicated adverse well conditions such as H_2S (three), sand (five), paraffin (two), and scale (two). Twenty-three of the 30 failures indicated wear and tear as the root cause.

These repeated failures, totaling 30 events, could indicate that the cause of the first failure may not have been fully resolved, and further investigation is warranted. Additional operator analysis may allow for a better understanding of the operating environment to which these SPPE valves are exposed, and the suitability of the valve design to the operating conditions (e.g., H_2S, sand, etc.). If more detailed information on root causes of reported events is submitted to SafeOCS, further analysis of the data will be conducted.

5 Conclusions and Next Steps

The SafeOCS SPPE failure reporting program's objectives are to capture and share essential information about SPPE failures and contribute to an improved understanding of the nature of the failures, including their operating environments and contributing factors and causes.

Toward these objectives, this year's report provides more detail on exposure data and measures used to support analyses of SPPE failures. SafeOCS also conducted several new analyses in 2019:

- An additional data source—OGOR-A well shut-in status codes—was used along with the INC and WAR data sources to identify failures that may not have been reported to SafeOCS.
- The failure rate methodology was revised to account for required SPPE testing frequencies, given that most reported failures were detected through leakage testing. This adjustment reduces the potential for ascertainment bias, which can occur when some valve types in the SPPE population are evaluated for potential failure more often than others.
- Disproportionality analyses of water depth, and water cut ratio were evaluated in addition to well rate to understand better where SPPE failures occurred and characteristics of wells with SPPE failures. Few SPPE failures occurred for higher-producing wells or wells in deeper waters. The water cut analysis showed that wells with the lowest and highest ratios of water to total liquids produced could be associated with SPPE failures.
- To improve the accuracy of analyses involving corrective actions, an informal definition was developed for each corrective action term. The data collection form does not currently include these definitions.
- Several new analyses were performed to gain insight as to the nature of wear and tear failures, including more detailed evaluations of contributing factors, corrective actions, and time to failure. Perhaps most noteworthy among the findings, of the 49 wear and tear failures with sufficient data to determine the time to failure, nearly two-thirds occurred within three years of installation or last repair. This finding suggests that at least some of these failures cannot be explained solely as normal wear.
- Repeated failures, in which the same valve failed multiple times during the same year, were further evaluated to compare each operator's proportion of repeated SSV failures compared to their total reported SSV failures. The analysis showed that a third of reporting operators experienced repeated SSV failures, and 13 of 156 SSVs (8.3 percent) failed two or three times in 2019.

Some general observations can be drawn from the 2019 data and analyses:

- As in previous years, no failure resulted in an event with consequences for personnel health or safety or the environment.
- Most failures continued to be SSV gate and seat failures (internal leakage) caused by wear and tear and corrected by repairing the valve.
- The number of failures reported annually has grown each year since the program began in 2017. Despite evidence of underreporting found in analyses of other SPPE data, i.e., INC, WAR, and OGOR-A data, the increase in reporting from 2018 to 2019 was a relatively modest 10.3 percent (225 reports in 2019 compared to 204 in 2018). As in previous years, a few operators reported most failures, with three of 15 reporting operators accounting for 84.9 percent of the failure reports.
- The rate of SPPE failure in the GOM OCS is 0.28 percent or about one in 362 evaluations. Here, evaluation means when the valve is evaluated for potential failure through required leakage testing.
- Although 14 repeated failures were reported, no root cause failure analysis (RCFA) reports were submitted to SafeOCS for these failures. RCFAs represent a potentially rich source of information about SPPE failures, learnings from which could be shared with the industry to prevent similar occurrences.

Next Steps: Opportunities for Improvement

To improve the accuracy of the information in the SafeOCS database and share learnings from SPPE failures with industry and other stakeholders, BTS has identified several focus areas for next steps:

1. Revise the data collection form to improve data quality further and ensure answers are captured correctly. Specific form enhancements may include:
    a. Distinguish failure types (external leak, internal leak, failure to close, and failure to open) from contributing factors;
    b. Clarify failure type definitions (e.g., failure to close versus internal leak);
    c. Consider potential improvements to better capture other well contaminant information;
    d. Clarify when “activated in response to an ESD” should be selected, distinguishing between failures detected during emergency response versus ESD testing;
    e. Clarify the question “Was the well shut-in at the time of the failure?” to distinguish between a well already shut-in at the time of failure versus a well shut-in as a response action;

f. Clarify corrective action definitions;
g. Collect better information regarding repair actions; and
h. Consider potential improvements to capture SPPE time to failure information better.

2. Continue efforts to improve exposure data and measures for the following topics:
   a. Measuring component life, in cycles and time, to evaluate the testing and replacement frequencies;
   b. Quantifying operational impact in terms of production interruptions and deferrals when failures occur;
   c. Enhancing analyses of SPPE failure rates in subsea versus surface wells through evaluation of subsea versus surface well population data for the GOM OCS;
   d. Improving the accuracy of SSCSV failure rate calculations.
   e. Further evaluating well age as a potential factor in SPPE failures.

3. Work with stakeholders to improve the data collection process by focusing in the following areas:
   a. Improve operator participation in reporting.
   b. Identify opportunities to improve reporting of specific root cause failure analysis results and learnings that may have industry-wide benefit.

Appendix A: Oil and Gas Production Safety Systems Rule Background Information

The Bureau of Safety and Environmental Enforcement (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.[22] The rule is codified primarily in 30 CFR part 250, subpart H. In September 2018, BSEE published revisions to the 2016 Production Safety Systems Rule, which clarifies provisions for SPPE failure reporting.[23]

The rule defines an equipment failure as "any condition that prevents the equipment from meeting the functional specification," and requires reporting of such failures. More specifically, pursuant to 30 CFR § 250.803, effective December 27, 2018, operators must report according to the following:

> *(a) You must follow the failure reporting requirements contained in section 10.20.7.4 of ANSI/API Spec. 6A for SSVs, BSDVs, GLSDVs and USVs. You must follow the failure reporting requirements contained in section 7.10 of ANSI/API Spec. 14A and Annex F of ANSI/API RP 14B for SSSVs (all incorporated by reference in § 250.198). Within 30 days after the discovery and identification of the failure, you must provide a written notice of equipment failure to the manufacturer of such equipment and to BSEE through the Chief, Office of Offshore Regulatory Programs, unless BSEE has designated a third party* as provided in paragraph (d) of this section. A failure is any condition that prevents the equipment from meeting the functional specification or purpose.*
>
> *(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 failure. If the investigation and analyses are performed by an entity other than the manufacturer, you must ensure that the analysis report is submitted to the manufacturer and to BSEE through the Chief, Office of Offshore Regulatory Programs, unless BSEE has designated a third party as provided in paragraph (d) of this section. You must also ensure that the results of the investigation and any corrective action are documented in the analysis report.*
>
> *(c) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such changes, report the design change or modified procedures in writing to BSEE through the Chief, Office*

[22] Final Rule, 81 Fed. Reg. 61,833 (Sept. 7, 2016).
[23] Final Rule, 83 Fed. Reg. 49,216 (Sept. 28, 2018).

of Offshore Regulatory Programs, unless BSEE has designated a third party as provided in paragraph (d) of this section.

(d) BSEE may designate a third party to receive the data required by paragraphs (a) through (c) of this section on behalf of BSEE. If BSEE designates a third party, you must submit the information required in this section to the designated third party, as directed by BSEE.*

- *Currently, the designee of the Chief of OORP is the U.S. Department of Transportation's Bureau of Transportation Statistics (BTS). Operators submit this information through *www.SafeOCS.gov*, where it is received and processed by BTS. Reports submitted through *www.SafeOCS.gov* are collected and analyzed by BTS and protected from release under the Confidential Information Protection and Statistical Efficiency Act (CIPSEA) (44 U.S.C.101).

APPENDIX B: RELEVANT STANDARDS

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

- Subpart H - Oil and Gas Production Safety Systems (§§ 250.800 - 250.899)

Selected Relevant Industry Standards Incorporated by Reference in 30 CFR Part 250

- 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

Appendix C: 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).

Active Operator: Operating company with active wells in the Gulf of Mexico (GOM).

Active Well: an active well is a well that is past the drilling and completion phase, is not undergoing a workover and has not yet been temporarily or permanently abandoned. An active well may or may not have production volumes reported during the year, and the well may be an injection well or a production well. BSEE requires that operators must maintain and test SPPE valves on all active wells whether they produce or not during the month. An active well, for purposes of this annual report, is considered a well with SPPE valves providing a barrier to the fluids in the reservoir.

API Number: API (American Petroleum Institute) numbers are assigned by regulatory agencies, usually the oil and gas commission for the state where the well is to be drilled. For drilling operations in the GOM Outer Continental Shelf (OCS), the Bureau of Safety and Environmental Enforcement (BSEE) is the regulatory body that approves the Applications to Drill for new wells and thus assigns the API numbers. These numbers are assigned as part of the well permitting process, and they may be the same as the well permit number.

Ball Valve: A valve that employs a ball mechanism which rotates to open or close the flow passage.

Barrel: The standard unit of measure of liquids in the petroleum industry; it contains 42 U.S. standard gallons.

Barrel of Oil Equivalent (BOE): The amount of energy resource (in this document, natural gas) that is equal to one barrel of oil on an energy basis. The conversion assumes that one barrel of oil produces the same amount of energy when burned as a certain volume natural gas. In this report, the factor used was 5.62 cubic feet.

Borehole: When drilling to explore or develop hydrocarbon reservoirs, the hole drilled is referred to as the borehole.

Casing String: Long sections of connected pipe that are lowered into a wellbore and cemented. The pipe segments (called "joints") that make up a string are typically about 40 feet (12m) in length, male threaded on each end, and connected with short lengths of double-female threaded pipe couplings.

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

Choke: The device (also known as the well choke and installed in the wellhead) that controls the flow of fluid to or from a well by changing the flow area that the produced or injected fluids flow through.

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

Floating Rig (or Mobile Offshore Drilling Unit - MODU): A drilling rig that is movable, such as a drill ship or a semi-submersible rig. In some cases, a platform rig can access subsea wells.

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.

Hydrocarbons: Oil and gas.

Injection Well: A well into which fluid (water or gas) is injected for the purpose of enhancing hydrocarbon recovery.

Intervention Vessel: A marine vessel capable of performing non-rig work (such as wireline or coil tubing) on a subsea well without removing the wellhead.

Landing Nipple: A completion component fabricated as a short section of heavy wall tubular with a machined internal surface that provides a seal area and a locking profile. Landing nipples are included in most completions at predetermined intervals to enable the installation of flow-control devices, such as plugs and chokes.[24]

Loss of Primary Containment: An unplanned or uncontrolled release of any material from primary containment, including non-toxic and non-flammable materials (e.g. steam, hot water, nitrogen,

[24] Schlumberger Oilfield Glossary, https://www.glossary.oilfield.slb.com.

compressed CO_2, or compressed air).[25]

Master Valve (also called Production Master): The main shut-in valve in the well tree is designated as the Master Valve. Most well trees have two Master Valves, an Upper Master Valve (typically designated the SSV or the USV) and a Lower Master Valve which is in the vertical run of the tree and further upstream and closest to the well.

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

Producing Operator: An operator owning wells that are in the production phase or producing oil and/or gas.

Production Platform: The structure, either fixed or floating, that contains the equipment necessary to produce well fluids including extraction, separation, treatment, and measurement.

Production Master: See Master Valve.

Production Tubing: a tube used in a wellbore through which produced fluids travel from the reservoir (production zone) to the wellhead/Christmas tree. Production tubing is installed in the drilled well after the casing string is run and cemented in place. Production tubing protects wellbore casing from wear, corrosion, and deposition of by-products (such as sand, silt, paraffin, and asphaltenes).

Production Well: A well from which oil or gas is extracted via the production tubing.

Tree: See Well Tree.

Water Cut: The ratio of water produced compared to the volume of total liquids produced.[26]

Wellbore: The volume contained within the cross-sectional area of the borehole, which may contain the casing, tubing, and production or injection well fluids.

Well Rate Range: A range assigned to each well based on either its average production rate (sometimes referred to as "well rate") or well test rate in BOE/day to allow grouping of wells by their flow rates. The ranges include zero (0), <100, 100-499, 500-999, 1,000-4,999, 5,000-9,999, and >10,000 BOE/day.

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[25] International Association of Oil & Gas Producers (IOGP) Report 456, Process safety – Recommended Practice on Key Performance Indicators (Nov. 2018).
[26] Schlumberger Oilfield Glossary, https://www.glossary.oilfield.slb.com.

Well Test: A test performed to measure the production fluid rates from a producing well or the fluid rate to an injection well, respectively.

Well Test Rate: The flow rate for a well as measured in a well test. The well test rates are reported (via a "well test report") on a 24-hour (i.e. "per day") basis and include values for oil, gas, and water volumes. For comparison purposes, these rates are sometimes converted to barrel of oil equivalents (BOE/day), which is equal to the barrels of oil plus the barrel oil equivalent of the produced gas. A typical GOM gas conversion factor is 5.62 thousand standard cubic feet of gas is equal to one BOE.

Well Tree: An assembly of valves, spools, and fittings used to regulate the flow from the pipe, or production tubing, in a producing well (oil or gas) or an injection well (water or gas). Well trees typically include two Master valves, at least one Wing valve, and the well choke. A well tree is commonly called a "Christmas tree."

Wellhead: A general term used to describe the component at the surface of an oil or gas well that provides the structural and pressure containing interface for the drilling and production equipment. The primary purpose of a wellhead is to provide the suspension point and pressure seals for the well casing strings.

Wing Valve: A valve in the well tree that is designated as the Wing Valve. Typically, this is the last valve on the wellhead (i.e., above or downstream of the Master Valves) and often in the horizontal section of 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.[27]

[27] Adapted from RigZone. (2017). How Do Wirelines and Slicklines Work? http://www.rigzone.com/training/insight.asp?insight_id=323.

Acronym and Abbreviation List

ANSI: American National Standards Institute

API: American Petroleum Institute

BOE: Barrel of oil equivalent

BSDV: Boarding Shutdown Valve

BSEE: Bureau of Safety and Environmental Enforcement

BTS: Bureau of Transportation Statistics

CFR: Code of Federal Regulations

CIPSEA: Confidential Information Protection and Statistical Efficiency Act

CO_2: Carbon Dioxide

DVA: Direct Vertical Access

ESD: Emergency Shutdown

FOIA: Freedom of Information Act

GLSDV: Gas Lift Shutdown Valve

H_2S: Hydrogen Sulfide

HSE: Health, Safety, and Environment

INC: Incident of Noncompliance

ISD: Industry Safety Data

Mcf: Thousand cubic feet

MMBOE: Million barrels of oil equivalent

NTL: Notice to Lessees

OEM: Original Equipment Manufacturer

OCS: Outer Continental Shelf

OGOR-A: Oil and Gas Operations Reports-Part A

RCFA: Root Cause Failure Analysis

SME: Subject Matter Expert

SPPE: Safety and Pollution Prevention Equipment

SSV: Surface Safety Valve

SCSSV: Surface Controlled Subsurface Safety Valve

SSCSV: Subsurface Controlled Subsurface Safety Valve

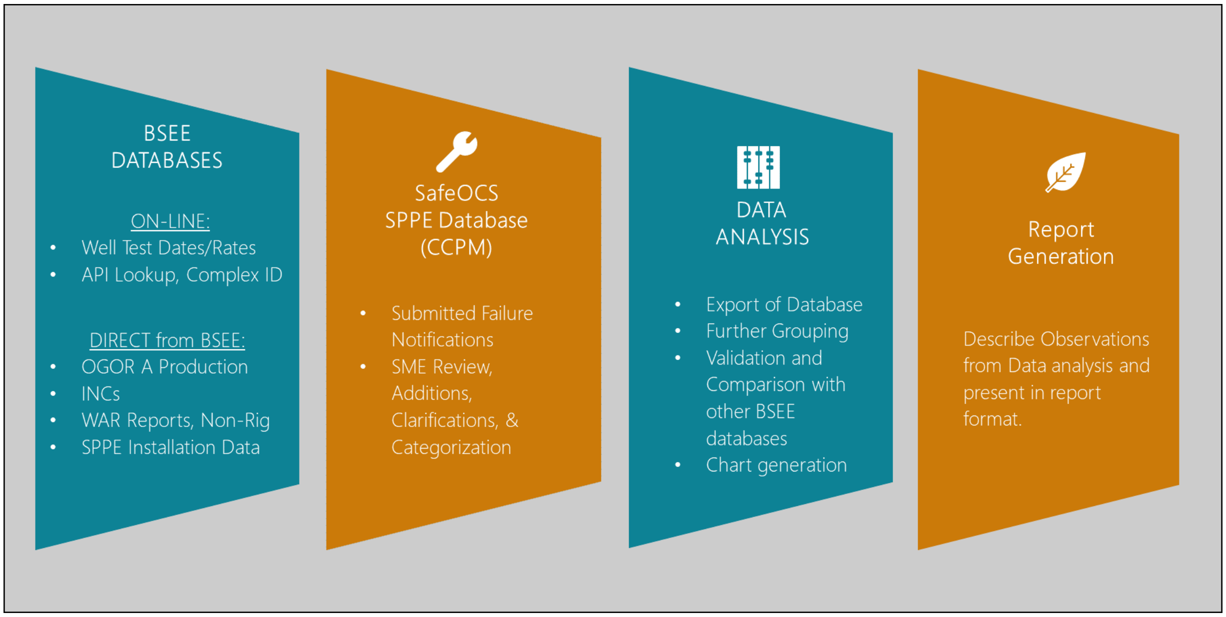
USV: Underwater Safety Valve

WAR: Well Activity Report

APPENDIX D: DATA ANALYSIS METHODOLOGY

The diagram below depicts the major steps in developing the SPPE annual report.

Figure 19: SPPE Annual Report Steps



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

WAR and Non-Rig WAR Reports

Operators are required to provide a summary of daily activities in all Outer Continental Shelf (OCS) regions (Gulf of Mexico (GOM), Pacific, and Alaska), reported via Well Activity Reports (WARs) on a weekly basis in the GOM Region and daily in the Pacific and Alaska Regions, per 30 CFR 250.743. The well activities reported in WAR include work accomplished on OCS wells during all phases (drilling, completion, workover, re-completion, non-rig interventions, and abandonment) including any repairs or replacements of sub-surface SPPE valves (SSCSVs and SCSSVs).

BTS reviewed the non-rig WAR data submitted to BSEE in 2019 to provide context for the SPPE component failures reported to SafeOCS. Since surface SPPEs are typically repaired at surface and not normally addressed by well interventions, they are not normally found in WAR reports. When subsurface safety valves fail, however, they are often repaired, replaced, or substituted using a non-rig well interventions. Accordingly, the wireline operation reports in the non-rig WAR data document these interventions and can sometimes be used to cross reference the timing and occurrence of subsurface SPPE failures reported to SafeOCS. Although only one of the SPPE failures reported to

SafeOCS in 2019 was found in the WAR data, there were 22 additional failures identified in the WAR data that were not reported to SafeOCS.

Of the 23 SPPE failures found in the WAR data, 21 were associated with the SCSSVs and two were associated with an SSCSV. Determining the cause of these failures from the WAR data is difficult as the available data is limited to the repair activities, and previous operating history is unavailable. One cause of failure that is often discernable from the WAR data is a leak in the downhole control line. Six of the 23 failures resulted from this type of failure. The failure types for the other 17 failures is unknown.

Additionally, the resulting outcome of these 23 SPPE failures can be determined from the WAR data. In 22 cases, the failures resulted in the SCSSV being "locked open" by wireline operations. In one case, a control line leak at the wellhead, the failure was repaired by removing the tree. The 22 locked open SCSSVs resulted in 10 cases of an SSCSV being installed, five cases of a wireline-retrievable SCSSV being set, four cases of a wireline plug being set, and three lockouts were conducted to facilitate permanent abandonment operations on the well.

Well Test Reports and Well Production Volumes

Procedures for well production reporting and well test reporting in the 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 test reports are based on BSEE procedures[28] which require lessees (i.e., operators) to submit well test volume reports at least semiannually or at a different frequency as approved in the commingling permit for each producing well. During well testing, the well's fluid stream is temporarily segregated from the other wells. While segregated, the oil, gas, and water volumes are measured using flow meters installed on the corresponding streams exiting a three-phase separator, typically called a "well test separator" over a specified time period (usually 4 hours). The well test volume (barrels of oil, thousand cubic feet of gas (mcfg), and barrels of water) are then divided by the test time to establish the well test rate on a "per day" basis. To make comparisons between oil and gas wells, however, these rates are typically converted to barrel of oil equivalents per day (BOE/day) by adding the oil rate to the equivalent gas rate. The equivalent gas rate is equal to the gas volume (in thousand cubic feet of gas, or mcfg) divided by 5.62.[29] The 5.62 factor is the number of cubic feet in an equivalent barrel of oil and is

[28] 30 CFR 250.1151(a)(2), 250.1204(b).
[29] 30 CFR 203.73. See also U.S. Department of the Interior, Minerals Management Service, Appendix 1 to NTL No. 2010-N03, at page 38.

the industry standard to calculate an equivalent gas rate.

If the well test rate was provided in the notification, BTS compared it to the most recent well test prior to the failure from well test data from BSEE. For purposes of this report, the well test units were converted to barrel of oil equivalents per day (BOE/day) to allow comparison between wells. Well test rates were only used to validate the well rate range for each well with a reported failure, which was calculated using the average production for the well (if any) in the month of the failure and the three months prior to the failure.

The well rate range for each of the producing wells in the 2019 OGOR-A database (including those with a reported SPPE failure) was determined by BTS using the average production rate for each well. The average production rate was calculated by adding each well's total produced oil volume and total gas volume (after converting to BOE volume) in 2019, and then dividing the sum of those two volumes by the number of days the well was in production in 2019.

Well Shut-in Status Codes in OGOR-A

In addition to each well's produced volumes, the OGOR-A data contains various monthly codes for the status of each shut-in well called "Shut-In Reason Codes." Two of the shut-in codes indicate when wells are shut in for SSV problems (code 63) or SCSSV problems (code 45). If the first month that the well status was reported as 63 or 45 fell in 2019, BTS counted it as an SSV or SCSSV failure, respectively. OGOR A does not provide any additional information about the failure. Since the data is monthly, determining the actual failure date of the SPPE is not possible.

SPPE Population in the Gulf of Mexico

All SPPE installations are reported to BSEE, and these are captured in a database provided by BSEE to BTS. The database includes fields such as type of SPPE, date of installation, date of removal (if removed), removed from service flag, well API number, and other information. BTS used this information to determine the number of currently active SSVs, USVs, BSDVs, SCSSVs, and SSCSVs in the GOM. This improved the population estimate and allowed the population to be reported by SPPE type.

BTS considered 11,849 SPPE valves as "active SPPE valves" after reviewing the list of 19,322 valves provided by BSEE and restricting the list to valves installed in the GOM OCS that were not flagged as removed or out of service.

Incidents of Noncompliance (INCs)

BTS reviewed the INCs that mentioned SPPE to determine if the deficiency described in the INC was a reportable SPPE failure.[30] The following INCs were included in this analysis:

Table 9: Potential Incidents of Noncompliance (PINCs) Included in Analysis

PINC	Number of INCs	Short Description
P-412	37	SSV, USV, or BSDV had internal leakage
P-241	14	SCSSV failed to close within 2 minutes
P-280	16	SSV failed to close within 45 seconds
P-240	11	SCSSV was not tested every 6 months
P-307	1	SSV was not tested monthly
P-102	3	Shutdown device did not perform its function when commanded
P-319	0	BSDV was not tested monthly
Total	*82*	*N/A*

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

Within these INCs, each identified SPPE failure that met the reporting requirements for SafeOCS notification was counted as an SPPE failure reported in an INC. The INCs involving 2019 SPPE failures were then used to cross reference the SPPE failures during the same period to determine if they were also reported in SafeOCS.

Applicable Potential INCs (PINCs):

- P-102 Do end-devices (i.e., shutdown devices, shutdown valves, SSVS, and other shutdown controls) perform their designed function upon receiving a signal (pneumatic or electronic) transmitted by a sensor that has detected an abnormal condition?

- P-103 Is each surface or subsurface safety device, which is bypassed or blocked out of service, out of service due to start-up, testing, or maintenance and is it flagged and monitored by personnel?

- P-240 Does the SSV and SDV on all other process components close within 45 seconds after automatic detection of an abnormal condition or activation of the ESD?

[30] The BSEE Potential Incident of Noncompliance (PINC) List can be accessed at bsee.gov/what-we-do/offshore-regulatory-programs/offshore-safety-improvement/potential-incident-of-noncompliance-pinc.

- P-241 Does the Surface-Controlled SSSV close within 2 minutes after the ESD or fire detection system shut-in signal has closed the SSV?

- P-280 Is each Surface-Controlled SSSV installed in a well tested when installed or reinstalled and at intervals not exceeding 6 months and removed, repaired and reinstalled, or replaced, if it does not operate properly?

- P-281 Is each subsurface-controlled SSSV installed in a well removed, inspected, and repaired or adjusted, and reinstalled or replaced as necessary at intervals not exceeding 6 months for those valves not installed in a landing nipple and 12 months for those valves installed in a landing nipple?

- P-307 Is each SSV tested for operation at least once each month, with no more than 6 weeks elapsing between tests, and repaired or replaced if found defective?

- P-319 Is each BSDV tested for operation at least once each month, not to exceed 6 weeks and if the device does not function properly, or if a liquid leakage rate or a gas leakage rate is observed, the valve must be removed, repaired, and reinstalled, or replaced?

- P-412 Is each wellhead completion equipped with a minimum of one master valve and an operable SSV located above the master valve, in the vertical run of the tree?

Boreholes Data

The water depth for active wells and wells with SPPE failure in the GOM OCS was determined using boreholes data provided by BSEE. The boreholes table includes a water depth field, which was joined with the well API number to determine the water depth for active wells.

Well API Number

In cases where the well API number was not reported on the SafeOCS notification, BTS utilized the BSEE Data Center API lookup and the OGOR A production data to determine the well API number associated with each SPPE failure based on other information provided such as lease number, well name, and complex ID. Since GLSDVs and BSDVs are often associated with multiple wells, no API well number was assigned to those failures.

Well Count Determination from OGOR-A Data

The total GOM OCS well count was determined using production data from BSEE's OGOR-A reports downloaded from the BSEE Data Center. Each well is identified with an API number and has a reported well status code for every month. Status codes were used to exclude well API numbers for wells that did not meet the definition of "active well" in this SPPE report. Specifically, well with the following status codes were excluded:

- 1 Actively Drilling
- 2 Inactive Drilling
- 14 Wellbore Temporarily Abandoned
- 15 Completion Abandoned
- 16 Plugged and Abandoned
- 17 Well Work in Progress

Any well that was reported as "active" in at least one month was counted as an active well during 2019. The active wells were similarly counted for each operator, in addition to the operators' total production.

APPENDIX E: TYPICAL SPPE VALVE COMPONENTS

The following table describes the components typical of each type of SPPE valve.

Table 10: Typical SPPE Valve Components

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

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

APPENDIX F: HSE INCIDENTS

A health, safety, and environment (HSE) incident can generally be defined as an event that results in consequences to health, safety, or the environment. For purposes of this report, an 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 (H_2S and Other) that result in process or equipment shutdown
- Muster for evacuation
- Structural damage
- Spill < 10,000 gallons (238 bbls)

APPENDIX G: SPPE CERTIFICATION AND CLASSIFICATION

Certification

SPPE certifications fall under four types (Table 11). 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 11: Certification Status of Reported SPPE

SPPE Certification	Percent of Reports
Newly installed certified SPPE pursuant to ANSI/API Spec Q1	14.7%
Newly installed certified SPPE pursuant to another quality assurance program	0.0%
Previously certified under ANSI/ASME SPPE-1	71.6%
Non-Certified SPPE	2.2%
Not Answered	11.6%

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

SSV, BSDV, and USV Class and Type

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, 44.6 percent were Class 1 and 29.4 percent were Class 2. The class was not reported for the remaining 26.0 percent of SSV and BSDV events or any of the USV failures. BSDVs are further categorized as either automatic or manual. All 5 failed BSDVs reported to SafeOCS were automatic.

Subsurface Safety Valve Class

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 44 reported SCSSV and SSCSV failures, 14 were Class 1, six were Class 2, one was both Class 1 and Class 2, and four were Class 3s. The remaining 19 did not report the class.