Oil and Gas Production Safety System Events

2018 Annual Report

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

REPORT
OBSERVE
PREVENT
SafeOCS

2018 ANNUAL REPORT

OIL AND GAS PRODUCTION SAFETY SYSTEM EVENTS

U.S. Department of Transportation
Bureau of Transportation Statistics

ACKNOWLEDGEMENTS

Bureau of Transportation Statistics

Patricia Hu
Director

Rolf Schmitt
Deputy Director

Produced under the direction of:

Demetra Collia
Director, Office of Safety Data and Analysis

Recommended Citation:

Bureau of Transportation Statistics. *Oil and Gas Production Safety System Events - 2018 Annual Report*. Washington, D.C.: United States Department of Transportation, 2019.
https://doi.org/10.21949/1504098

Quality Assurance Statement

The Bureau of Transportation Statistics (BTS) provides high-quality information to serve government, industry, and the public in a manner that promotes public understanding. Standards and policies are used to ensure and maximize the quality, objectivity, utility, and integrity of its information. BTS reviews quality issues on a regular basis and improves its programs and processes to ensure continuous quality improvement.

Notice

This document is disseminated under an Interagency Agreement between the Bureau of Safety and Environmental Enforcement (BSEE) of the U.S. Department of the Interior (DOI) and the Bureau of Transportation Statistics (BTS) of the U.S. Department of Transportation (DOT). The U.S. Government assumes no liability for the report's content or use. The Interagency Agreement adheres to the Economy Act of 1932 as amended (31 USC 1535) and to the Federal Acquisition Regulations 6.002. To the best of DOI and DOT's knowledge, the work performed under the agreement does not place BTS in direct competition with the private sector.

TABLE OF CONTENTS

List of Figures

List of Tables

EXECUTIVE SUMMARY

The 2018 Annual Report: Oil and Gas Production Safety System Failures, produced by the Bureau of Transportation Statistics (BTS), summarizes safety and pollution prevention equipment (SPPE) failures on production oil facilities in the Outer Continental Shelf (OCS).

This report is based on data from 204 failure notifications submitted to SafeOCS in 2018.

Key findings in 2018 are as follows:

- The 2018 reported failures represent 12,174 SPPE valves in service and 5,476 active wells in the Gulf of Mexico OCS. Of all active wells, 162 (3.0 percent) had one or more reported SPPE.
- None of the 204 reported SPPE failures in the Gulf of Mexico were characterized as health, safety, and environmental (HSE) incidents and therefore posed minimal risk to production operations personnel or the environment.
- The most significant failure incidents, ranked by potential consequence, were external leaks, or loss of containment (LOC). In 2018, 13 failures were related to external leaks. Twelve (12) of these failures were leaks of control fluids (instrument air, instrument gas, or hydraulic fluid); and one was a small leak of well fluids to the atmosphere, in which the amount was too low to be considered an HSE event.
- The majority of the SPPE failures (74.5 percent) were categorized as internal leaks. Internal leaks generally pose less risk than other types of failures such as external leaks and the valve failing to close. Failure to close was the second most reported type of failure at 14.7 percent.
- Operator participation in the SafeOCS SPPE reporting program has improved. The 14 operators that reported SPPE failures represented 24.1 percent of 58 total active operators, operated 66.8 percent of the active wells (compared to 32.6 percent in 2017), and accounted for 62.3 percent of production from the Gulf of Mexico OCS.
- Most failures were on low production wells. Over three quarters (78.4 percent) of the failures occurred on wells producing less than 500 BOE/day (barrel of oil equivalent/day), with almost half (45.1 percent) of those producing less than 100 BOE/day. Less than 1.0 percent of the failures were associated with wells producing more than 5,000 BOE/day.

- Surface safety valves (SSV) experienced the most failures. Of all reported failures, 80.7 percent were SSV failures. The majority of the SSV failures were internal leaks (81.6 percent). Only 7.4 percent of SSV failures reported were "Failure to Close", which posed a higher potential risk than internal leaks, but did not lead to an HSE event. Most of the equipment failures (81.2 percent) were detected through leakage testing.
- The overall failure rate of all SPPE valves in the Gulf of Mexico in 2018 is 1.7 percent.
  - Boarding shutdown valves (BSDVs) had the highest failure rate out of each valve type. In 2018, there were 165 operating BSDVs with 5 reported failures, representing a 3.0 percent failure rate.
  - SSVs had the second highest failure rate. In 2018, there were 5,689 operating SSVs with 163 reported failures, representing a 2.9 percent failure rate.
- *Wear and tear* was the most frequently reported root cause of SPPE component failures (71.4 percent). There was not sufficient information on the date of valve installation and the hours or cycles of usage for the individual SPPE valves to determine the age of failed equipment. Further research into the high percentage of *wear and tear* cases is recommended.
- Reporting on SPPE failures to SafeOCS appears to be incomplete. More than half of the SPPE failures (57 of 102) identified in BSEE's INC or WAR records were not reported to SafeOCS.

1 INTRODUCTION

The SafeOCS program was established in August 2013 through an interagency agreement between BTS and the Department of the Interior's Bureau of Safety and Environmental Enforcement (BSEE). The SafeOCS program is a resource to help industry members capture and share key lessons from significant near misses[1] and other safety events. Its objective is to identify, prevent, and mitigate potential high-consequence risks by measuring and analyzing failure data while protecting the anonymity of the data providers (e.g., operators and equipment manufacturers).

The SafeOCS program includes the reporting of safety and pollution prevention equipment (SPPE) failures as mandated under 30 CFR 250.803. Background information on the regulatory requirements is provided in Appendix A. Title 30 CFR 250.803 requires operators to submit SPPE failure reports when specific SPPE does not perform as designed. This requirement incorporates the industry reporting practices found in relevant American Petroleum Institute (API) Standards and Specifications (see Appendix B).

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 second annual report on SPPE failures. Other key information provided in the report includes operational impact and failure causes. The data analyses are based on reported SPPE component failures occurring on production facilities in the Gulf of Mexico. These failures were submitted directly to BTS through SafeOCS or provided to BTS by BSEE. BSEE defines a failure as any condition that prevents the equipment from meeting its functional specifications.[2] 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.

New to the 2018 analyses is a reconciliation of the SPPE data reported to SafeOCS, using BSEE Incident of Noncompliance data (INC data) and Well Activity Report data (WAR data). Use of these additional data sources resulted in a more complete set of failures that occurred in the Gulf of Mexico during 2018 operations. Importantly, SPPE failures identified in the INC and WAR data were used only as supporting information and have not been added to the total number of SPPE failure events reported to SafeOCS.

[1] Defined in Appendix C: Glossary and Acronym List.
[2] 30 CFR 250.803(a).

Additionally, to characterize failures with appropriate context, other BSEE databases were used. Specifically, the BSEE well test data,[3] well production volumes extracted from the U.S. Department of the Interior (DOI) Oil and Gas Operations Reports – Part A (OGOR-A),[4] and SPPE installation data[5] were used. See the Data Collection and Validation section of this report for more information. Appendix D includes information on how these data sources were used.

As was done with last year's report, BTS retained subject matter experts (SMEs) in production operations, subsea engineering, equipment testing, well equipment design and manufacturing, root cause failure analysis, quality assurance and quality control, and process design to assist in reviewing failure notifications for accuracy and consistency. In addition, the SMEs provided support for data analysis on the BSEE-provided data (e.g., WARs, well tests, well production volumes, SPPE installation data, and INCs) to further enhance the SafeOCS data analysis.

[3] Specified Well Test Detailed Report: 2008 – Present (https://www.data.bsee.gov/Well/Files/Well-Test-2008-Present.pdf).
[4] Oil and Gas Operations Reports – Part A (OGOR-A), via BSSE Data Center (https://www.data.bsee.gov).
[5] SPPE valve data, provided by BSEE.

2 Safety and Pollution Prevention Equipment

In general, safety and pollution prevention equipment (SPPE) promotes safety and protection of the human, marine, and coastal environments. The specific SPPE covered by the Oil and Gas Production Safety Systems Rule (30 CFR part 250, subpart H) protects personnel and the environment by stopping the flow and preventing uncontrolled flow of well fluids (crude oil, natural gas, and water) in case of an emergency or system failure. The SPPE consist of specifically designated safety valves, actuators, and their control systems, which are required not only by BSEE regulations and rules, but also by industry standards, or company policies. Currently, they include the following types of valves:

- Boarding Shutdown Valves (BSDVs)
- Surface Safety Valves (SSVs)
- Underwater Safety Valves (USVs)
- Subsurface Safety Valves
  - Surface Controlled Subsurface Safety Valves (SCSSVs)
  - Subsurface Controlled Subsurface Safety Valves (SSCSVs)
- Gas Lift Shutdown Valves (GLSDVs) - beginning December 28, 2018 under the revised BSEE rule.[6]

Surface Wells vs. Subsea Wells

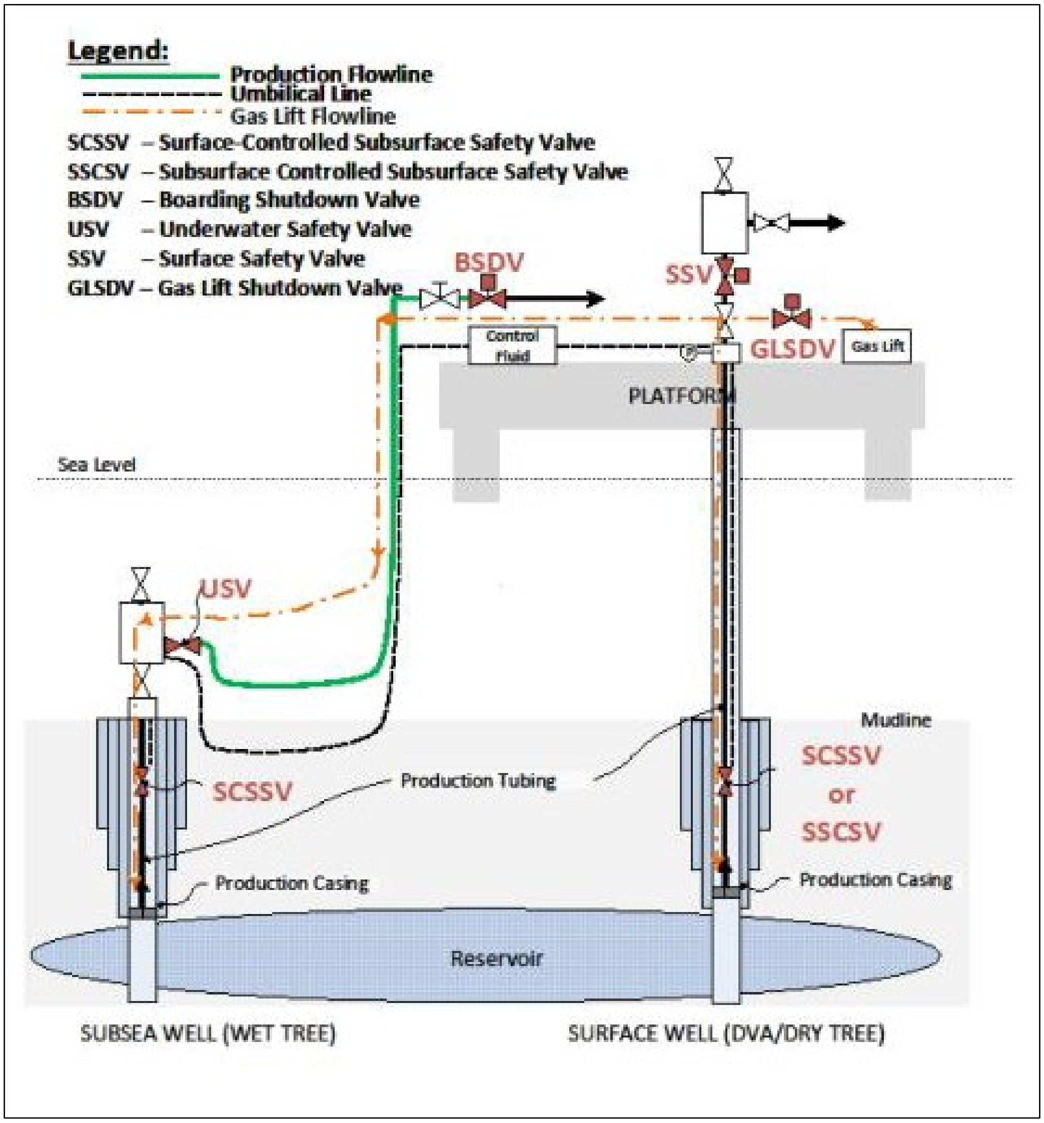
The SPPE valves are found in both surface wells and subsea wells on the equipment system, or what is referred to as the "tree." Surface well trees, also called dry trees or direct vertical access (DVA) trees, are located above sea level, allowing the operator direct access to the wellbore from the production platform. Subsea well trees, also called wet trees, are located on the seafloor, allowing 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). Although some variations may be found within well trees in the field, Figure 1 illustrates the typical locations of these SPPE valves on each type of well.

A typical surface well will be equipped with at least one subsurface safety valve (SCSSV or SSCSV) in the tubing below the seafloor or mudline and a surface safety valve (SSV) on the wellhead. A subsea well will be equipped with at least one subsurface safety valve and an underwater safety valve (USV). However,

[6] See Appendix A for more information about the rule.

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 30 CFR 250.833,[7] a production master or wing valve may qualify as a USV under API Spec. 6A and API Spec. 6AV1, which provides redundancy in the equipment to allow for 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

NOTE: "DVA" refers to direct vertical access.

[7] 30 CFR 250.833 – Specification for underwater safety valves (USVs).

SPPE Valve Types

SPPE valves are operated in the open position to allow the production well to flow, but 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 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. 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.

Most SSVs and USVs are sliding gate valves that are operated hydraulically (using hydraulic oil pressure) or pneumatically (using gas pressure). SSVs are found on surface wells, whereas USVs are located on subsea wells. BSDVs, utilized for flowlines of subsea wells and located on the platform, are commonly gate or ball valves. Both gate and ball valves are operated either manually or automatically. Manual valves use a manually operated handle or hand wheel, and automated valves use a hydraulic or pneumatic actuator to open or close the valve. GLSDVs are also either gate or ball valves, and are commonly used on surface wells, but could be installed on 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 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). As an alternative to pulling the tubing to retrieve a failed SCSSV, a smaller wireline retrievable SCSSV can be installed in the wellbore (and utilize the original control line pressure) after locking open the original SCSSV. Although this type of valve may lower the well flow rate and would need to be pulled to allow future deeper interventions in the well, it is surface controlled and 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 from the well. It is run (or pulled) using wireline and set in the well's tubing string. The valve is typically held open by a spring. At flow rates higher than the designed shut-down rate, the differential pressure across the valve causes it to close and stop the well from flowing. The SSCSV is installed using wireline and can similarly be retrieved for maintenance or to allow other downhole operations to be conducted. SSCSVs may be used in surface wells, but are not used 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 30 CFR 250.880. Table 1 summarizes the testing frequencies and leakage requirements in general. However, exceptions can apply for different types of wells, subject to BSEE's approval.[8]

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.

NOTE: Units of cc per minute are cubic centimeters (also seen as cm^3) per minute. Units of scf per minute are standard cubic foot per minute.

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

3 Data Collection and Validation

Data Confidentiality— CIPSEA

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

SPPE Failure Reporting

SPPE failures can occur during normal operations, when automatically called upon by the control system to close, or when the SPPE valve is manually closed, or shut-in, for its routine function test. 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: handwritten forms, Microsoft Word documents, PDFs, and website forms. In total, the 2018 annual report is based on 204 reported notifications.

Data Validation

BSEE maintains publicly available databases on information collected from companies in the field or submitted to BSEE. BTS utilized data provided by BSEE to validate SafeOCS data and to enhance the SafeOCS data analysis. The specific BSEE data sources include the following:

- Well Activity Reports (WARs)
- Well Test Reports
- Well Production Volumes - OGOR-A
- SPPE Installations
- Incidents of Noncompliance (INCs)

Well Activity Report (WAR)

Operators are required to provide a summary of daily activities in all Outer Continental Shelf (OCS) regions (Gulf of Mexico, Pacific, and Alaska), via WARs on a weekly basis in the Gulf of Mexico

Region and daily in the Pacific and Alaska Regions, per 30 CFR 250.743. The well activities reported in WARs include work accomplished on OCS wells during all phases (drilling, completion, workover, recompletion, non-rig interventions, and abandonment) including any repairs or replacements of subsurface SPPE valves (SSCSVs and SCSSVs). BTS reviewed the wireline operation reports in the WAR data to cross reference the timing and occurrence of subsurface SPPE failures reported to SafeOCS. There was a total of 16 additional failures identified in the WAR data that were not reported to SafeOCS.

Well Test Reports

Procedures for well test reporting in the OCS regions are codified in BSEE regulations 30 CFR part 250 subparts K and L. *Subpart L - Oil and Gas Production Measurement, Surface Commingling, and Security* describes the measurement and production well testing requirements. BSEE requires[9] lessees (i.e., operators) to submit well test reports detailing daily fluid volumes at least once every month for each producing well; they are reported in barrel of oil equivalents per day (BOE/day). See Appendix D for more information on well test reporting. These well test reports were used to provide context to the potential impact of each failure, by using the fluid volume information to categorize wells and associated events.

Well Production Volumes – OGOR-A

BSEE utilizes the well test reports to calculate and allocate the total commingled monthly volumes produced from a facility to the volumes produced by each well. A well's production volume is the quantity of oil, gas, and water produced from a well during a specified period (typically monthly).

SPPE Installation Data

The SPPE installation data provided by BSEE includes the type of SPPE valve, location, and installation date. This information was used to estimate the total number of SPPE valves associated with wells in the Gulf of Mexico and, in some cases, to determine the age of equipment at the time of failure (see methodology section in Appendix D for more details).

Incidents of Noncompliance (INCs)

BSEE also provided BTS with data on Incidents of Noncompliance (INCs) in the Gulf of Mexico. Field INCs may be issued by BSEE inspectors whenever they are on the 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 BSEE, depending on the severity of the violation, will issue a

[9] 30 CFR 250.1151(a)(2).

warning, a component shut-in, or a facility shut-in enforcement action. The INC will provide the operator with direction on how to come into compliance and offer an opportunity to take appropriate action. The INCs involving 2018 SPPE failures were used to cross reference SPPE failures reported to SafeOCS during the same period. 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 Gulf of Mexico in 2018 but may have not been reported to SafeOCS.

4 DATA ANALYSIS

Subpart H covers production operations on the OCS, which includes BSEE's Gulf of Mexico, Pacific, and Alaska regions. For 2018, SafeOCS received equipment failure notifications for operations in the Gulf of Mexico only, which accounts for over 99 percent[10] of all offshore production in the United States. Most wells are in the central Gulf of Mexico, close to the Louisiana shoreline. Exact locations of reported equipment failures are not disclosed in this document to protect the confidentiality of the data.

SafeOCS received 204 SPPE failure notifications for 2018. Table 2 provides an overview of the reported SPPE failures in 2018 compared to reported failures in 2017. The number of active wells (5,476) was slightly lower in 2018; however, the number of reporting operators increased from 7 to 14, an increase from 12.3 percent to 24.1 percent in total operators in the Gulf of Mexico. Note that reporting operators are those that reported failure notifications in 2018. This points to a slight increase in participation, albeit lower than the optimal response rate. The number of active wells operated by the reporting operators also increased from 32.6[11] to 66.8 percent, and their production in the Gulf of Mexico increased from 39.8 to 62.3 percent. This means that an increasing number of operators are aware of the SPPE failure reporting requirement. These operators are also generally reporting more complete information than in 2017 reports. Similarly, the number of SPPE failures reported to both BSEE (found in the Incident of Noncompliance data or Well Activity Reports) and to SafeOCS was notably higher (4 in 2017 vs. 45 in 2018), which indicates that participation is improving but still well below 100 percent.

The proportion of failures ranges from 0.5 to 3 percent per SPPE valve type, with an overall proportion of failure of 1.7 percent, which is higher than 2017. This increase could be due to the increased reporting rather than a change in performance. The proportion-of-failure calculation uses the SPPE valve counts from the BSEE data provided on the SPPE installations.

[10] BSEE Data Center, Outer Continental Shelf Oil and Gas Production data, December 2018 volumes.

[11] A new definition of active wells was adopted for 2018 in which wells with SPPE valves in place and acting as a barrier to fluids in the reservoir are the ones counted (see Glossary in Appendix C). These can be producing wells (producing oil, gas, or water), wells capable of producing (some wells are in an active status but not producing any fluids at that time), or injection wells. This change in definition was retroactively applied to 2017 data for this annual report.

Table 2: SPPE Numbers at a Glance

	2017	2018
Active Operators	57	58
Producing Operators	55	53
Total Active Wells	5,624	5,476
Reporting Operators	7	14
Reporting Operators' Percent of Active Wells	32.6%	66.8%
Reporting Operators' Percent of Production	39.8%	62.3%
SPPE Failures Reported to SafeOCS[12]	112	204
Surface Well SPPE Failure Events	108	198
Subsea Well SPPE Failure Events	4	6
SPPE Failures Reported in INC or WAR	104	107
SPPE Failures Reported to SafeOCS *and* INC/WAR	4	45
SPPE Failure Type		
HSE Incident	0	0
External Leak	4	13
Failed to Close on Platform	6	13
Internal Leak on Platform	88	139
Failed to Close Away from Platform	6	17
Internal Leak Away from Platform	8	13
Failed to Open	2	6

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

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

Data Validation

Analysis of the WAR data indicates that 16 surface controlled subsurface safety valves (SCSSVs) experienced failures during 2018 that were not reported to SafeOCS. These failures resulted in the tubing retrievable SCSSV's being "locked open" and wireline retrievable subsurface controlled subsurface safety valves (SSCSVs) or SCSSVs being installed in the wells. No other SPPE failures were identified in the WAR data for 2018.

Similarly, a comparison was done of the number of SPPE failures found during BSEE inspections to the total number of SPPE failures reported to SafeOCS. Because the number of INCs involving SPPE valves only represent those failures occurring while BSEE is visiting the platform (i.e., still a subset of all failures),

[12] This total does not include SPPE failures identified in the INC or WAR data provided by BSEE.

determining the total number of SPPE failures that occurred in the Gulf of Mexico in 2018 is not possible from the INC data. A total of 91 SPPE failures were documented in the BSEE INC database for 2018, of which 45 were reported to SafeOCS.

Who Reported Equipment Events

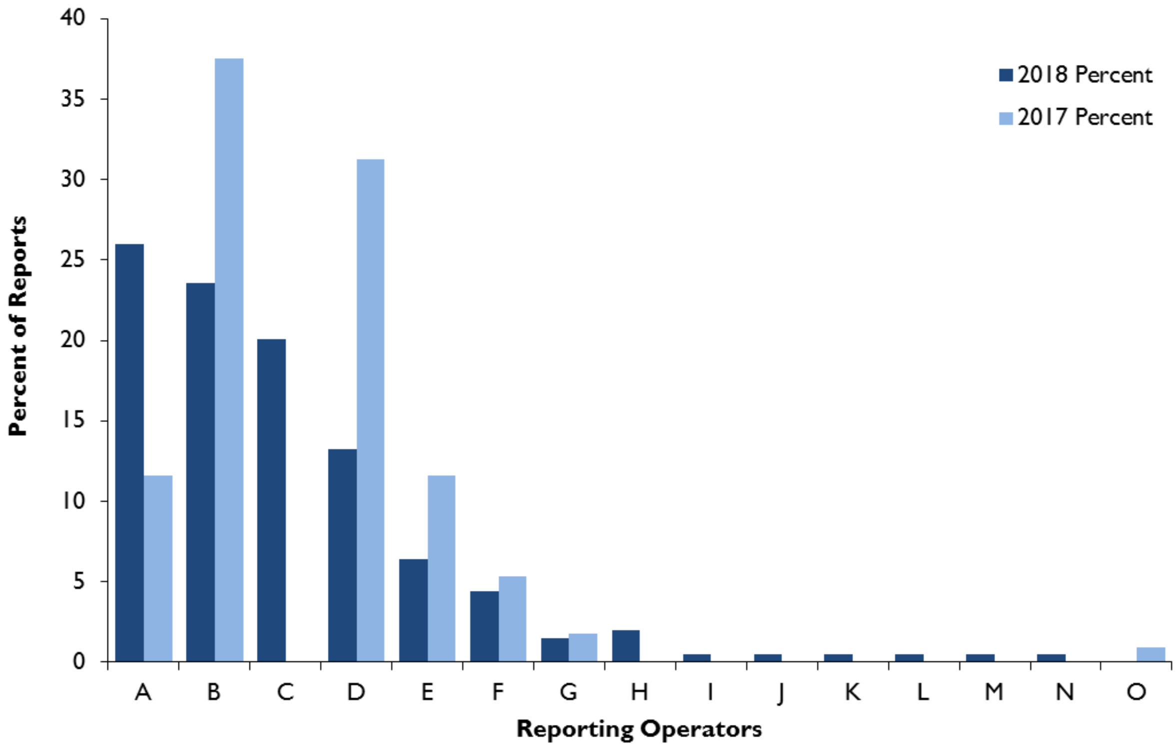
There were 58[13] active operators in the Gulf of Mexico OCS listed as operating active wells[14] (wells that may or may not be in production, but the operators' equipment is still on the well for which operators are responsible to test and maintain) in 2018 as compared to 57[15] in 2017. Fifty-three (53) operators, out of 58, had production from the Gulf of Mexico OCS in 2018 (i.e., producing operators). The remaining 5 operators were associated with active wells but without production in 2018. Operators with non-producing wells are still responsible for testing the SPPE and maintaining their wells. Fourteen (14) out of the 58 operators submitted SPPE failure reports (Figure 2) representing approximately a 12 percent increase from 2017, when 7 out of 57 operators reported SPPE failures to SafeOCS. The top 4 of the 14 reporting operators accounted for 82.8 percent of the failure reports, 55.7 percent of the active wells and 10.0 percent of total production from the Gulf of Mexico OCS. The percent of production is proportionally low because many of the active wells are low producing wells. The operators who did not report in 2017 contributed 25.0 percent of the 2018 reports.

[13] The number of operators with active wells was determined by using the Oil and Gas Operations Reports-Part A from BSEE for 2018.

[14] Defined in Appendix C: Glossary and Acronym List

[15] The 2017 annual report initially stated there were 59 operators with active wells in the concurrent year. Two companies were recorded with two different names and inadvertently counted twice; thus, 57 was the correct number of operators in 2017.

Figure 2: Percent of SPPE Reported Failures by Operators



NOTE: There are only 7 operators instead of 9 for 2017 because two of the reporting operators merged into one company, and one operator was reported with two different company names. Data was combined here for both 2017 and 2018. Operator names have not been disclosed to preserve reporter confidentiality.

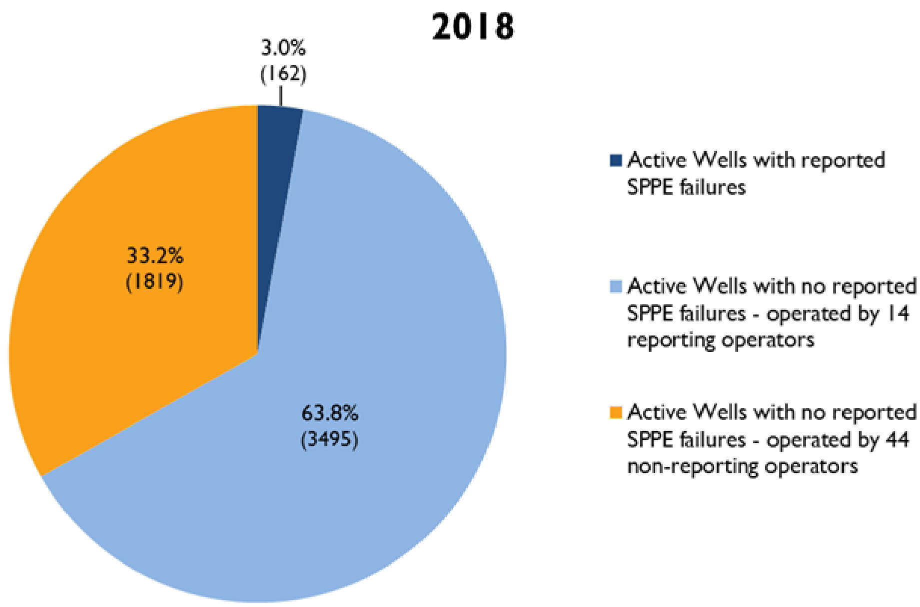
KEY: SPPE—Safety and Pollution Prevention Equipment

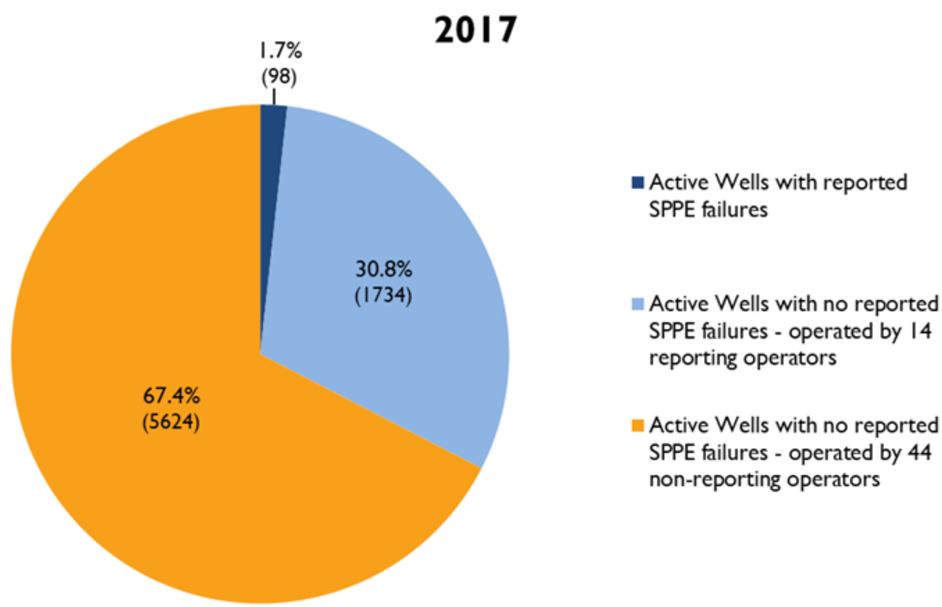
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

Figure 3 shows the distribution of active wells between reporting and non-reporting operators. Of the 5,476 active wells, 162 were associated with one or more reported SPPE failures. The 14 reporting operators represent just 24.1 percent of the total 58 operators, but they operate 66.8 percent of the active wells. This is a considerable increase from the 32.6 percent of active wells in 2017. These 14 operators also account for 62.3 percent of production from the Gulf of Mexico OCS. The remaining 44 operators with no reported failures operate 33.2 percent of the active wells and produce 37.7 percent of oil and gas produced in the Gulf of Mexico.

BSEE's INC data included SPPE related INCs for twenty operators in 2018. Compliance with reporting to SafeOCS varied among operators with SPPE related INCs. Of twenty operators with INCs for SPPE failures in 2018, three reported all their SPPE failures to SafeOCS, as required, seven reported a small percentage of their SPPE failures to SafeOCS, and ten did not submit any SPPE failures to SafeOCS.

Figure 3: Active Wells and Reporting Status of Operators





KEY: SPPE—Safety and Pollution Prevention Equipment

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

Details of Reported Equipment

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

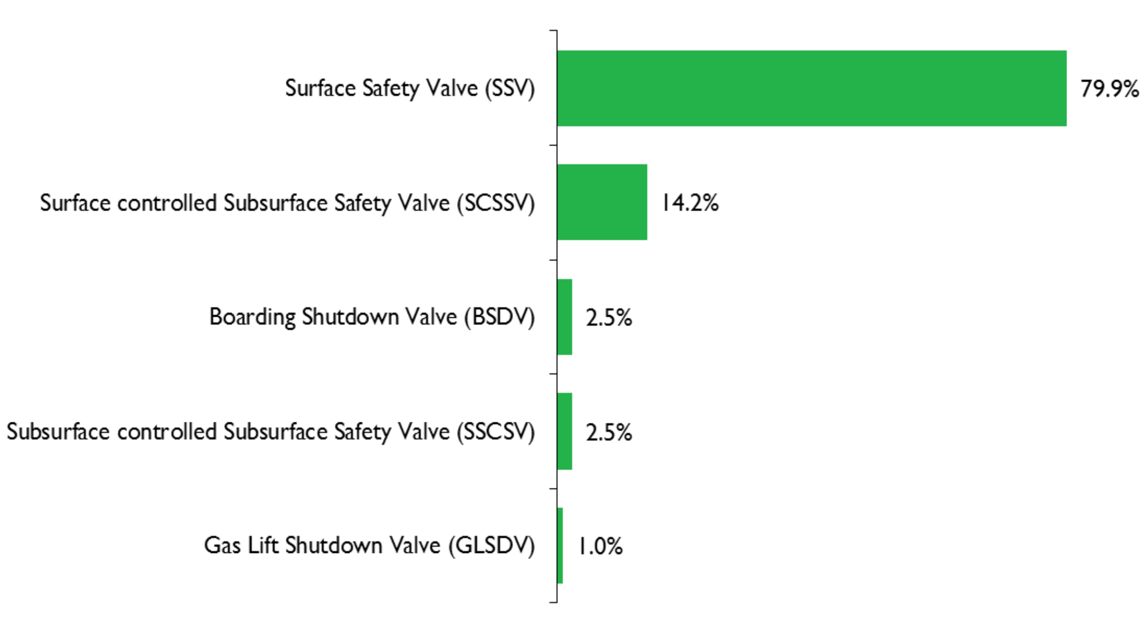
- SSV—Surface Safety Valves,
- BSDV—Boarding Shutdown Valves,
- USV—Underwater Safety Valves,
- SCSSV—Surface Controlled Subsurface Safety Valves,
- SSCSV—Subsurface Controlled Safety Valves, and
- GLSDV—Gas Lift Shutdown Valves.

There were 204 failures reported to SafeOCS in 2018. Of the 204 reported failures, 197 were on dry tree, or surface wells. The remaining 7 were on subsea wells, 5 of which were BSDVs, and 2 were SCSSVs. All of the reported failures were on producing wells. No failures were reported on injection wells in 2018.

Failure proportions by SPPE valve type are illustrated in Figure 4. Nearly 80 percent of the failures reported were on SSVs, even though SSVs represent just under half of the SPPE population. SSV failures are higher due to the higher required testing frequency and zero leakage requirement. Because SSVs are tested on a monthly basis, the opportunity to identify a failure is greater than a subsurface valve that is tested every 6 months.

The total number of valves in the Gulf of Mexico in 2018, varies across the SPPE valve types (Table 3). The proportion of failure for each valve type, based on the total population, ranges from 0 to 3.0 percent. SSVs and BSDVs had the highest proportions of failures. The SSVs' proportion of failure, based on the total population of SSVs in the Gulf of Mexico in 2018 is only 2.9 percent. On the contrary, BSDVs were a low percentage (2.5 percent, Figure 4) of total failures reported to SafeOCS; however, because they have the lowest population at 165, the proportion of failures is the highest out of the six SPPE valves (3.0 percent). Based on the total valve population, there is still a low proportion of SPPE valve failures occurring in the Gulf of Mexico, with only 1.7 percent of all valves experiencing a failure in 2018.

Figure 4: Reported SPPE Events by Valve Type



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

Table 3: SPPE Valve Populations in the Gulf of Mexico in 2018

SPPE Valve Type	Number of Failures Reported to SafeOCS	Population of Valves in the Gulf of Mexico	Proportion of Failures by Population of Valve Type in the Gulf of Mexico
SSV	163 (79.9%)	5,689	2.87%
SCSSV	29 (14.2%)	4,988	0.58%
SSCSV	5 (2.5%)	707	0.71%
BSDV	5 (2.5%)	165	3.03%
USV	0 (0.0%)	625	0.00%
GLSDV	2 (1.0%)	Not Available	Not Available
All Valves	*204 (100%)*	*12,174*	*1.7%*[16]

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

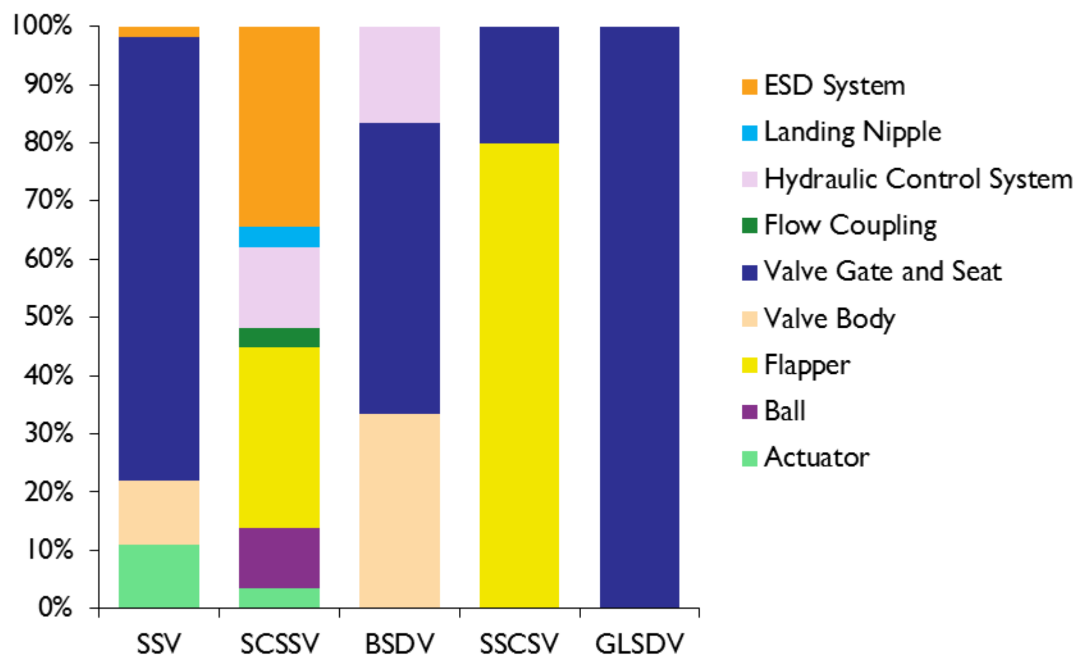
The frequency of required testing varies across the SPPE valves (Table 1), creating potential for identifying more failures in one type of valve versus another. For example, SCSSVs are required to be tested every 6 months whereas SSVs monthly, leading to a potential six-fold increase in the likelihood to identify a failure. In addition, the accepted leakage rates also differ among the valves with zero leakage

[16] 204 / 12,174 = 1.7%

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 there were more failures identified in SSVs compared to the other SPPE valves.

Multiple components make up each SPPE valve. SPPE valves and their corresponding components can be found in Appendix E. Figure 5 expands upon the failure reports by analyzing the type and number of components that failed within each valve. 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 valve gates and seats, but there were only 2 GLSDV failures reported. Failures of certain components could have a higher consequence than others. For example, a failure of the actuator could prevent the valve from closing when it is called upon, leading to an external leak of the control fluid. Flappers and valve gates and seats, on the other hand, are internal components. If they fail to seal, a leakage would initially be contained internally. The most common component failure reported was the valve gate and seat.

Figure 5: Failed Components within SPPE Valves Reported to SafeOCS



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

Failures and Potential Consequences

The majority (83.4 percent) of the reported SPPE failures occurred on the platform (SSVs, BDSVs, and GLSDVs - see Figure 1 for valve location) rather than in the wellbore tubing or below sea level. The majority of the SSV failures (163 reported failures) were internal leaks (81.6 percent), 13 SSV failures were external leaks (8.0 percent), 12 (7.4 percent) were SSVs that failed to close, and 4 (2.5 percent) were SSVs that failed to open.

Subsurface safety valve (SCSSV and SSCSV) failures accounted for 16.7 percent of the reported failures, with SCSSVs accounting for most of these. Half (50.0 percent) of the subsurface safety valve failures were due to failure of the valve to close. The remaining failures were internal leaks (38.2 percent) and a failure to open the valve (5.9 percent). BSDV failures were mostly internal leaks, with only one BSDV reported as a failure to close. The reported GLSDV failures were both internal leaks. As was the case in 2017, there were no reported USV failures in 2018.

To put SPPE failures in perspective, one must consider the potential consequences of such failures. An assessment was done to categorize SPPE failures based on the extent to which they degrade the installed well safety systems and potential consequence to personnel and the environment. These types of failures are described below. Their frequency is illustrated in Figure 6, and broken down further by SPPE valve in Table 4 below. There were 8 reported events that did not include enough information to determine the type of failure event. Additionally, reported SPPE failures could have more than one type of failure observed (e.g., both failed to close and failed to open), leading to a larger count of "number of reported events" in Figure 6 and the total count of reported failure types in Table 4 than the 204 SPPE failure events reported in 2018. Thus, in 204 SPPE failure events reported, 209 types of failures were observed. 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).

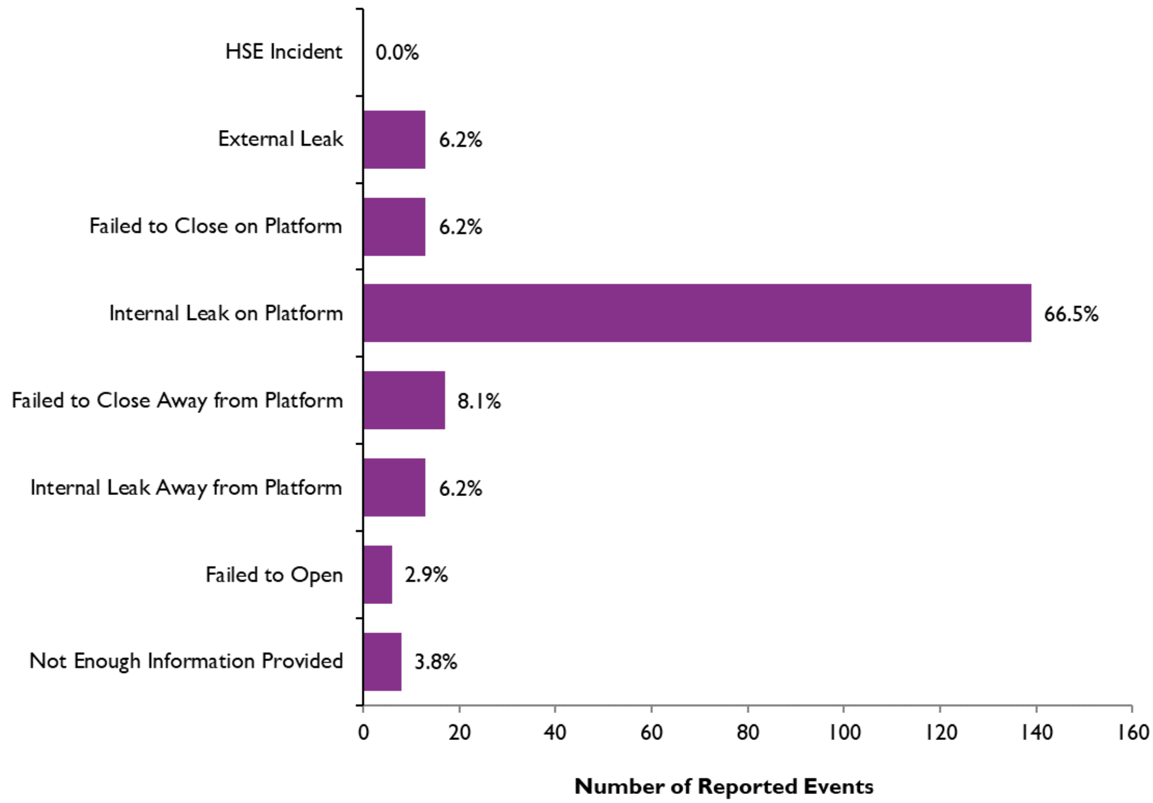
- The most significant type of failure reported is an external leak (e.g., loss of containment), where fluids would have the potential to leak into the environment or platform. The majority of external leaks are hydraulic fluids leaking from a component (e.g., from a hole in the bladder of the valve's actuator). Rarely, a more significant external leak may be found, where well fluids (oil and/or gas) could leak from the well directly. Thirteen (13) external leaks were reported:
  - — One report was considered a loss of containment of well fluids, where a small amount of well fluids leaked from an SSV to the atmosphere. The leak was small and not significant

enough to be considered an HSE incident (see Appendix F for HSE incidents).

— The remaining 12 external leaks were leaks of control fluid (instrument air, instrument gas, or hydraulic fluid) from the valve's actuator. In 3 of those 12 cases, the valve also failed to open or close or both, which could be a consequence of an actuator leak.

- 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. Thirteen (13) such failures were reported.
- 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. Internal leakage events were reported for 139 SPPE valves located on platforms.
- 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. Seventeen (17) such failures were reported.
- The fifth level of significance is an internal leakage in SPPE valves away from the platform (subsea or in the well). There were 13 failures reported for SPPE valves away from the platform where the internal leakage rate exceeded the allowable leakage rate.
- 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. There were 6 such failures reported.

Figure 6: Type of Reported Failure Events in Order of Significance



NOTE: More than one type of reported event could occur within a single reported failure. Six failure reports did not provide enough information to determine the type of 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**
External Leak	13				
Failed to Close	12	1		17	
Internal Leak	133	4	2	9	4
Failed to Open	4			2	
Not Enough Information Provided	5			2	1

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

Well Production

Operators are responsible for tracking the well production rates of oil, gas, and water for all producing wells on the OCS. This is accomplished by performing monthly well tests to calculate the fluid volumes (barrels of oil and water and standard cubic feet of gas), and calculating the barrel of oil equivalents per day (BOE/day) to get a rate of production volumes from the well, or "well rate" (see the Well Test and Well Rate section of Appendix D for a detailed explanation on how BOE/day was calculated). Depending on the well, the well rate can range from less than one BOE/day to over 10,000 BOE/day. The risk associated with a failure increases proportionally to the well rate, because the potential rate of the released volume is higher on wells with higher well test rates. Table 5 shows the SPPE failures grouped by well rate range using the average daily production from the well near the time of the failure.[17] The table also compares the failures with the well rate of all active wells in the Gulf of Mexico OCS. Most of the failures were associated with wells that produce less than 500 BOE/day. These wells are typically in shallow water posing a lower risk than higher producing wells in the deepwater environment.

In addition to the potential environmental consequences, equipment failures can cause significant production interruption. The failures on higher production wells could cause more production interruption, depending on the time required to repair the problem.

Table 5: Distribution of SPPE Failures and Active Wells by Well Rate for the Gulf of Mexico

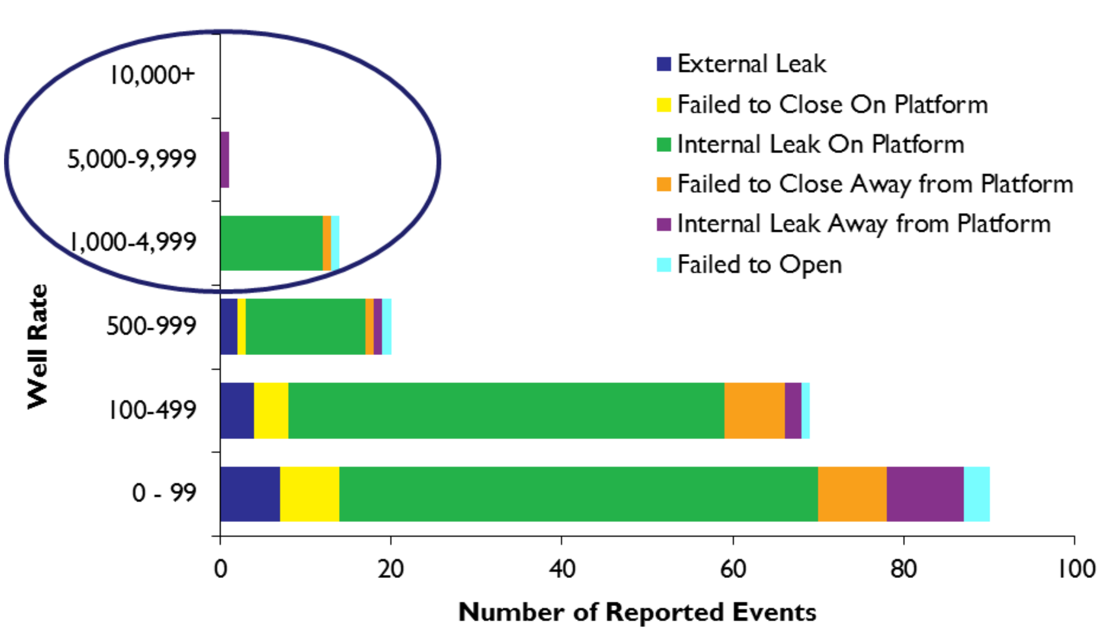
Well Rate (BOE/day)	Number of 2018 SPPE Failures	Number of Active Wells	Percent of SPPE Failures
0	4	2,104 (38.4%)	0.07%
<100	88	1,739 (31.8%)	1.61%
100-499	68	944 (17.2%)	1.24%
500-999	21	215 (3.9%)	0.38%
1,000-4,999	15	282 (5.1%)	0.27%
5,000-9,999	1	113 (2.1%)	0.02%
>10,000	0	79 (1.4%)	0.00%
Not Reported	7	-	-
Total	204	5,476	3.60%

SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program, and U.S. Department of Interior, Bureau of Safety and Environmental Enforcement, OGOR-A Reports.

[17] BSEE Data Center, OGOR-A Reports

In addition to the nature of the failure, the well's production rate is also important in evaluating the potential environmental impact. Figure 7 below shows that the higher producing wells (greater than 1,000 BOE/day) had no failures to close on the platform or external leaks, the most significant types of reported failures.

Figure 7: Type of Reported Failure by Well Rate



NOTE: 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.

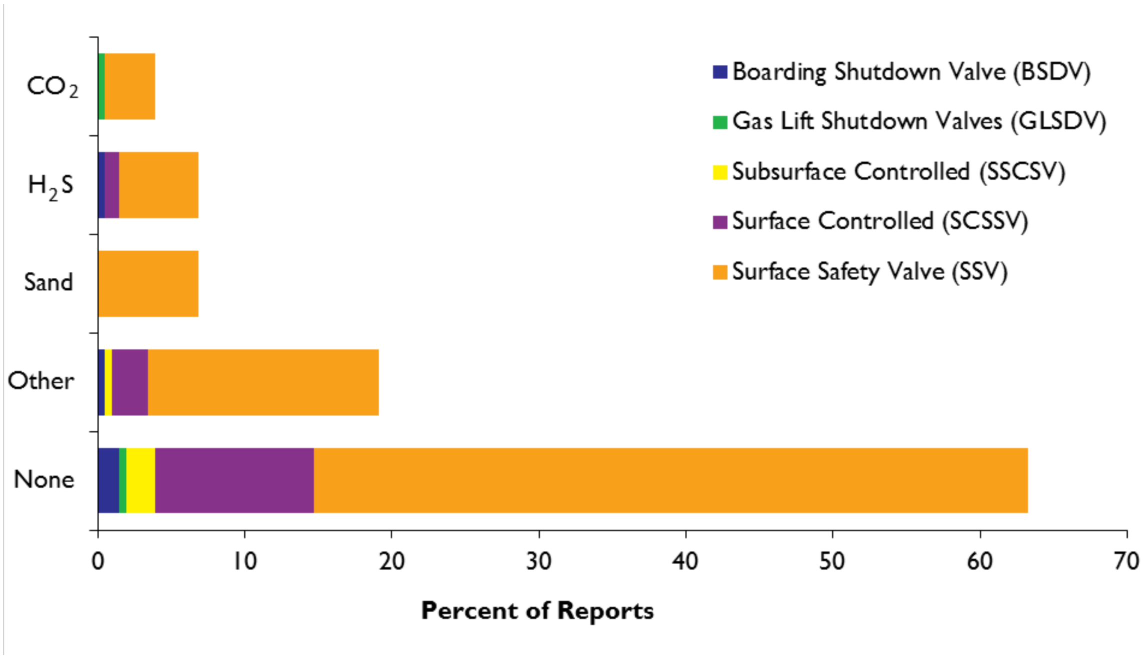
Contaminants

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 8). Certain wells naturally contain H_2S or CO_2, both of which can lead to corrosion damage to the equipment. Of the 14 failure reports indicating the presence of H_2S, 11 were associated with SSV failures, 2 with SCSSV failures, and 1 was a BSDV failure. Of the 8 failure reports indicating the presence of CO_2, 7 were associated with SSV failures and 1 was a BSDV failure.

Well fluids can also carry solids such as sand through the valves in the tree during production. The presence of sand can cause mechanical damage by eroding the equipment and could plug components within the production equipment. The failure reports indicating sand present in the wells included 13 SSV failures.

Even though there were well stream contaminants present, they may not have been the cause of the failure. More information on cause is described in the next section. More than half (63.1 percent) of the reports did not indicate any contaminants. None of the reports indicated more than one type of contaminant within a well. Reports in which "other" was selected for environmental conditions specified the following as contaminants: scale build-up; paraffin; cement; corrosion from non-use; and awaiting the root cause analysis report.

Figure 8: Well Stream Contaminants



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

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

Contributing Factors to Reported Failures

The factors contributing to the reported failure were assessed by SMEs qualitatively analyzing the reports including the failure narratives. As stated above (Figure 6), approximately 72 percent of reported failures were internal leaks on platform, which pose minimal risk; external leaks were 6.4 percent; valves failing to close were 14.9 percent; and valves failing to open were 2.5 percent.

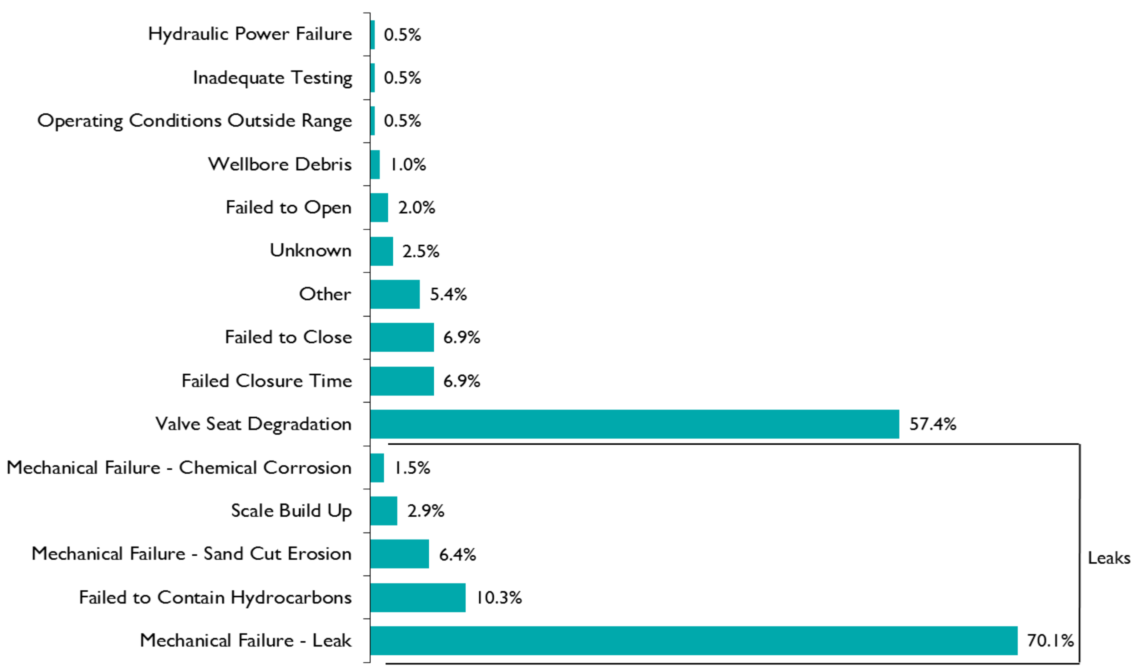
Operators were asked to report all contributing factors of the failure, for which the results are shown in Figure 9. The leaks were further broken down into the following contributing factors: *failed to contain hydrocarbons; mechanical failure - leak; mechanical failure - sand cut erosion; mechanical failure -*

chemical corrosion; and mechanical failure - atmospheric corrosion. A failure to contain hydrocarbons was designated when the internal leakage across the valve's sealing component was resolved by a simple service, such as a water wash or greasing the valve. *Mechanical failure - leak* was designated when the leak required a more robust corrective action, such as repairing or replacing a component or replacing the valve.

Mechanical failure - sand cut erosion was designated when the SPPE valve is degraded by sand contaminants. Chemical corrosion is internal corrosion usually caused by the presence of either H_2S or CO_2, whereas atmospheric corrosion is external corrosion usually caused by moisture or chlorides that affect susceptible metal surfaces. Depending on the metallurgy, the temperature, and the concentration of H_2S or CO_2, corrosion could occur quickly or from prolonged exposure.

Mechanical failure - leak and *valve seat degradation* were the two most common contributing causes, and often reported together. This is expected since internal leak was the most common type of reported failure, and valve gates and seats were the most commonly reported component failure. Most external leaks also included *mechanical failure - leak* as a contributing factor.

Figure 9: Contributing Factors to Equipment Events



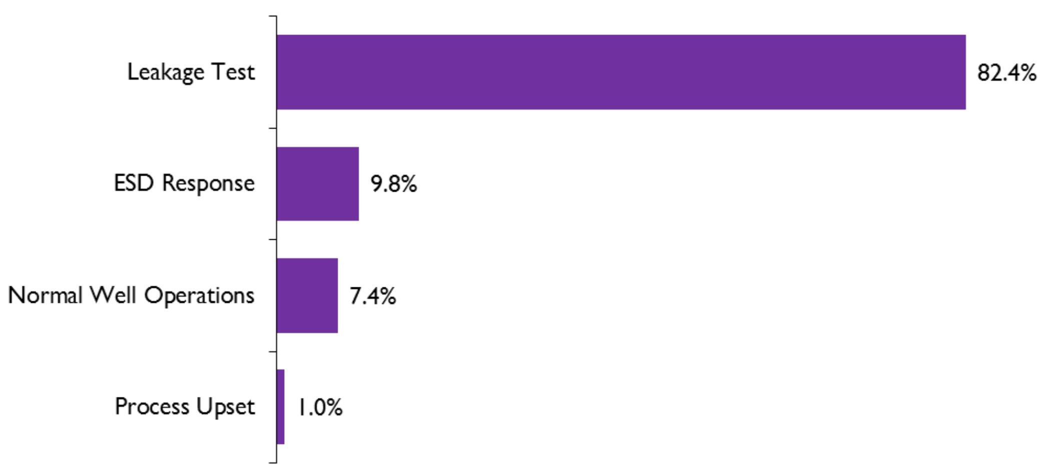
NOTE: Reporters could choose more than one contributing factor, resulting in a total greater than 100 percent.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

SPPE failures can be detected in several ways. For example, they can be found during testing, while the equipment is undergoing normal operation, or when production is required to halt – also called "shut-in" – due to abnormal or emergency conditions. Most of the failures in 2018 (82.4 percent) were found during routine leakage tests (see Figure 10). Failures during normal well operations (7.4 percent in 2018) are those that are detected during routine inspections, surveillance, or well closures for other operational reasons. "ESD response" (9.8 percent in 2018) means that the emergency shutdown (ESD) system was manually activated, shutting in all wells. ESD system testing is conducted regularly, with one section tested each month. If an SPPE valve leaks after being closed by the ESD system, it is considered an "ESD response" failure.

Similarly, a process upset could trigger an automatic or manual shut-in of a well's SPPE valve. A process upset is an event, such as a surge in production flow or an adjustment in pressure that causes the pressure or fluid level to be outside of the safety shutdown set points on the equipment. If an SPPE valve leaks after a process upset causes its closure, the method of detection is the process upset. Failures during process upsets comprised 1.0 percent of SPPE failures in 2018.

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. Just over half (54 percent) of the failure reports indicated that the well was shut-in when the failure occurred.

Figure 10: How Failures were Detected

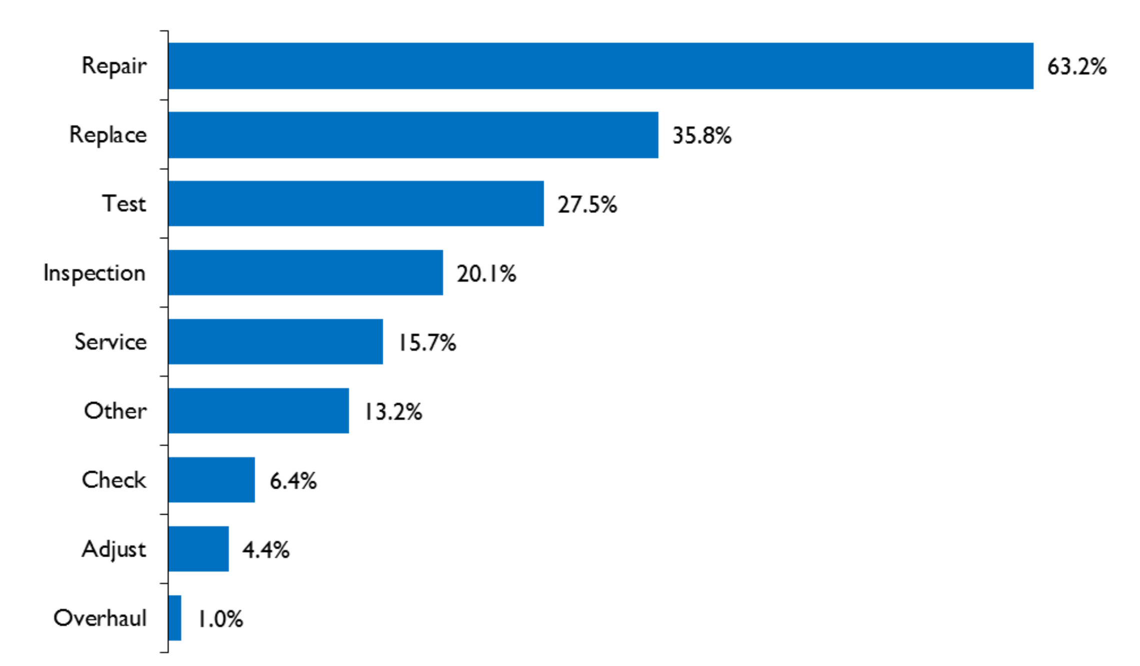


NOTE: Reporters could choose more than one method of detection.

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

Failure reports described corrective actions taken to address the failure (Figure 11). There could be one or more corrective actions per failure and can range from component servicing to repair or replacement. For example, some 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/or retesting. *Repair* and *replace* are the most common corrective actions.

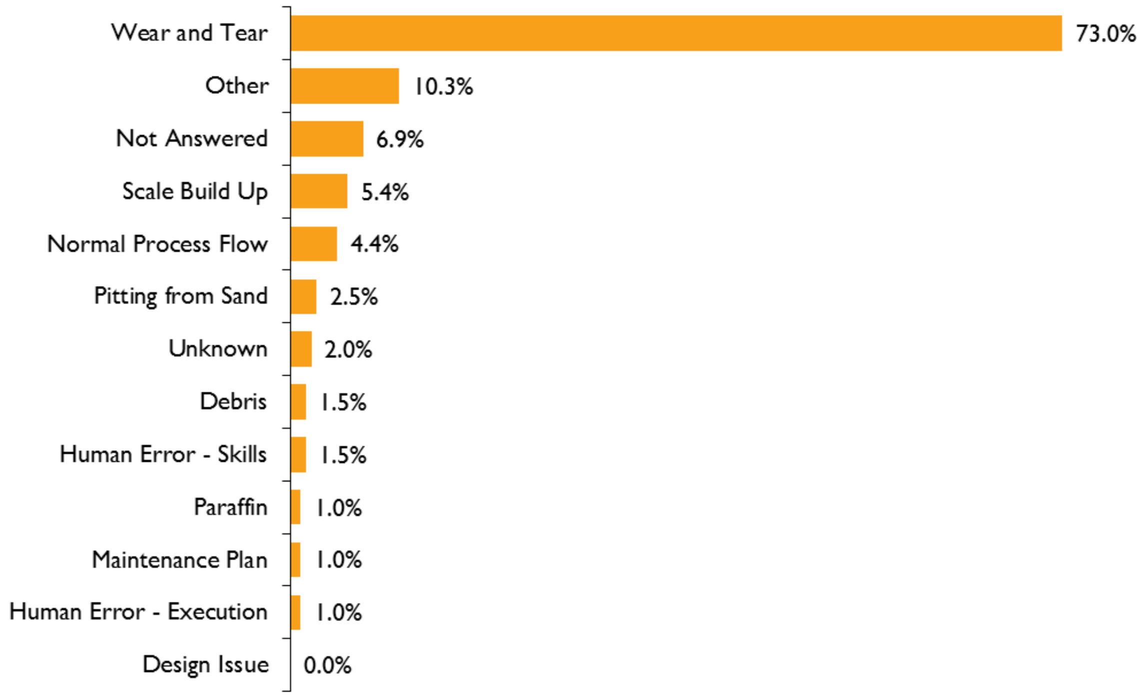
Figure 11: Reported Corrective Actions



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

Operators identified and reported the suspected root cause of the failure (Figure 12). *Wear and tear* was the most commonly reported root cause (73.0 percent) with SSVs making up most of those failures (130 out of 145, or 90.0 percent). Wear and tear was reported with almost every nature of failure, including those reporting contributing factors such as operation conditions outside of range, sand cut erosion, chemical corrosion, failure to open, and failure to close. There was not enough data regarding the installation date to determine the SPPE "age" (how long the SPPE valve was in place) to further explore what constitutes normal wear and tear.

Figure 12: 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.

Although ages of specific SPPE valves were not available in most cases, the "age" of the well's current producing zone associated with each failure was used as a proxy. Because most offshore wells can produce from two or more zones (i.e., strata in the earth beneath the ocean floor) over the life of the well, the age of well (the time from the original drilling to present time) can overestimate the age of the SPPE valve. Accordingly, a better estimate of the age of the SPPE valve would be to use the age of the producing zone, determined from production data. This age can be calculated from its first production date reported in the BSEE OGOR-A database. Table 6 below shows the breakdown of the age of the wells at the time of the SPPE failure. One-third of the failures occurred on wells that had been producing for less than 5 years. It is reasonable to correlate age of the well's current producing zone to the SPPE's age for those two groups; however, as the wells age beyond 5 years that correlation weakens. Nonetheless, the distribution of failures is similar across the 5-year groupings after the first 5 years of the well's producing years, and it is possible that some of the SPPEs have been in service the entire time. Although possible, an SPPE valve lasting 25 years is rare. The "actual" number of SPPEs in the 25+ year category is therefore likely lower than shown in the table.

Better reporting on valve installation date and repair history can lead to more accurate analysis and improve our understanding of factors affecting the reliability of these safety critical devices. As the SPPE valves are critically important to the safe production of oil and gas in the OCS environment, operators are strongly encouraged to submit as much detail as possible to the SafeOCS Input Form such that a more thorough evaluation of each failure can be conducted. The 2018 SPPE failure reporting form includes fields for component life as measured in cycles or hours since the last preventative maintenance, but does not currently include a field for installation date.

Table 6: SPPE Failures by Well Age

Well Age*	Number of Failures Reported	Percent of Failures Reported
0 - 1 yr	35	17.2%
1 - 5 yr	32	15.7%
5 - 10 yr	28	13.7%
10 - 15 yr	34	16.7%
15 - 20 yr	23	11.3%
25+ yr	47	23.0%
Not Available	5	2.5%

***NOTE:** Well age at the time of SPPE failure. Well age is estimated from the first production of the well, based on the first production date reported in BSEE's OGOR-A Reports.

SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program, and U.S. Department of Interior, Bureau of Safety and Environmental Enforcement, OGOR-A Reports.

The second most common root cause was "other," though most reporters did specify a root cause to elaborate the choice. Those choosing "other" specified several causes, such as scale build-up, debris, the presence of sand, and corrosion. Within "other," scale build-up accounted for 16.7 percent of reported root causes. Of the 15 wells with sand present (all SSV failures as shown in Figure 8 above), 5 specified that the presence of sand was the root cause of the failure. Three of the 5 were valves classified for service with the expectation of sand or other contaminants in the flow stream (Class 2, see Appendix G); two were Class 1 valves for service in normal operating conditions (i.e., not for sand exposure).

Repeated Failures

In 13 cases (12 SSVs and 1 SCSSV), the same component on the same SPPE failed more than once during 2018. Six reported SSVs had three repeated failures, and another six separate SSVs had two repeated failures within the year. These repeated failures (total of 32 events) indicate that the cause of the first failure may not have been fully resolved and further investigation is warranted. However, none of the failure notifications for these repeated failures indicate that a formal root cause analysis (RCA) is recommended or a further investigation is planned.

The SCSSV repeated failure was a case of leaving a small (1/4") needle valve in the control system closed. One of the SSV repeated failures was a small leak on the SSV actuator, which failed again within 1 month of the first failure. The actuator was replaced after the second failure. The most commonly reported SPPE failure in the remaining 28 repeated failures was internal leakage of the SSV.

Further analysis of these 28 repeated SSV failures revealed that the failed valves were of various models, pressure ratings, sizes, and classes, and the failures were reported by various operators on various manufacturers' valves. All except one failure was detected during leakage testing. Eighteen of the 24 failure reports indicated adverse well conditions such as H_2S (9), sand (6), and scale (3). Twenty-four of the 28 failures indicate wear and tear as the root cause. Nine of the 28 failures only required servicing, such as water washing, greasing, or cycling; these were the same 9 failures that reported the presence of H_2S. The remaining 19 failed were either repaired or replaced.

These repeated failures may indicate a need to conduct additional RCAs to better understand 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 RCAs and other, more detailed reports are submitted to SafeOCS, further review will be completed.

5 RESULTS AND CONCLUSIONS

SPPE failure data can be used to develop an improved understanding of the nature of the failures, their locations, operating environments and contributing factors leading to those failures. Key observations from the 2018 SPPE failure analysis include the following:

- There were no health, safety, and environment (HSE) incidents: None of the 204 reported SPPE failures in the Gulf of Mexico were characterized as a health, safety, and environmental (HSE) incident and therefore posed minimal risk to production operations personnel or the environment.
- There was only one external leak of well fluids, and the amount was too low to be considered an HSE event. The next most significant failure type, based on potential consequence, is an external leak, or loss of containment (LOC). In 2018, 13 failures were related to external leaks in 2018. Twelve (12) of these failures were leaks of control fluids (instrument air, instrument gas, or hydraulic fluid); only one failure resulted in a small leak of well fluids to the atmosphere, in which the amount was too low to be considered an HSE event.
- The majority of the SPPE failures (74.5 percent) were categorized as internal leakage. Internal leaks generally pose less risk than other types of failures such as external leaks and the valve failing to close. Failure to close was the second most reported type of failure at 14.7 percent.
- Operator participation in the SafeOCS SPPE reporting program has improved. The 14 operators that reported SPPE failures represented 24.1 percent of 58 total active operators, operated 66.8 percent of the active wells (compared to 32.6 percent in 2017), and accounted for 62.3 percent of production from the Gulf of Mexico OCS.
- Reporting on SPPE failures to SafeOCS appears to be incomplete. More than half of the SPPE failures (57 of 102) identified in BSEE's INC or WAR records were not reported to SafeOCS.
- The 2018 reported failures represent 12,174 SPPE valves in service and 5,476 active wells in the Gulf of Mexico OCS. Of all active wells, 162 (3.0 percent) had one or more reported SPPE.
- Most failures were on low production wells. Over three quarters (78.4 percent) of the failures occurred on wells producing less than 500 BOE/day (barrel of oil equivalent/day),

with almost half (45.1 percent) of those producing less than 100 BOE/day. Less than 1.0 percent of the failures were associated with wells producing more than 5,000 BOE/day.

- Surface safety valves (SSV) experienced the most failures. Out of all reported failures, 80.7 percent were SSV failures. The majority of the SSV failures were internal leaks (81.6 percent). Only 7.4 percent of SSV failures reported were failure to close, which posed a higher potential risk than internal leaks, but did not lead to an HSE event. Most of the equipment failures (81.2 percent) were detected through leakage testing.
- The overall failure rate of all SPPE valves in the Gulf of Mexico in 2018 is 1.7 percent.
    - Boarding shutdown valves (BSDVs) had the highest failure rate out of each valve type. In 2018, there were 165 operating BSDVs with 5 reported failures, representing a 3.0 percent failure rate.
    - SSVs had the second highest failure rate. In 2018, there were 5,689 operating SSVs with 163 reported failures, representing a 2.9 percent failure rate.
- *Wear and tear* was the most frequently reported root cause of SPPE component failures (71.4 percent). There was not sufficient information on the date of valve installation and the hours or cycles of usage for the individual SPPE valves to determine the age of failed equipment. Further research into the high percentage of *wear and tear* cases is recommended.

Next Steps: Opportunities for Improvement

The analysis of 2018 SPPE failure data confirms the most problematic components and operating conditions from which improvement opportunities can be identified. To that end and to improve the accuracy of the information in the SafeOCS database, BTS will focus on the following data improvement areas:

1. Revise the SPPE data collection approach to further improve data quality and ensure all possible answers are captured correctly.
2. Identify opportunities to improve operator participation in reporting failures to SafeOCS.
3. Focus data quality efforts and data analysis on the following topics:
    a. Measuring component life, in cycles and time, to evaluate the testing and replacement frequencies;
    b. Identifying the most common causes and contributing factors to prioritize problem solving efforts;

c. Collecting specific root cause investigation results and learnings from OEMs and third parties that may have industry-wide benefit; and
d. Quantifying operational impact in terms of production interruptions and deferrals when failures occur.

4. Evaluate the potential to obtain SPPE test data, to better estimate failure rates.

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.[18] The rule defines an equipment failure as "any condition that prevents the equipment from meeting the functional specification," and requires reporting of such failures.

In September 2018, BSEE published revisions to the 2016 Production Safety Systems Rule (PSSR), which clarifies provisions for SPPE failure reporting.[19]

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.*

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

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

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

- ANSI/API Specification 6A (ANSI/API Spec. 6A), Specification for Wellhead and Christmas Tree Equipment, Nineteenth Edition, July 2004; Errata 1 (September 2004), Errata 2 (April 2005), Errata 3 (June 2006) Errata 4 (August 2007), Errata 5 (May 2009), Addendum 1 (February 2008), Addenda 2, 3, and 4 (December 2008)
- API Spec. 6AV1, Specification for Verification Test of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service, First Edition, February 1, 1996; reaffirmed April 2008
- ANSI/API Specification 17D, Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment, Second Edition, May 2011
- ANSI/API Recommended Practice 17H, Remotely Operated Vehicle Interfaces on Subsea Production Systems, First Edition, July 2004, Reaffirmed January 2009
- ANSI/API Specification Q1 (ANSI/API Spec. Q1), Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry, Eighth Edition, December 2007, Addendum 1, June 2010
- API 570, Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems, Third Edition, November 2009.
- ANSI/API Spec. 14A, Specification for Subsurface Safety Valve Equipment, Eleventh Edition, October 2005, Reaffirmed June 2012.
- ANSI/API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems, Fifth Edition, October 2005
- API RP 14C, Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms, Seventh Edition, March 2001, Reaffirmed: March 2007
- API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, Fifth Edition, October 1991; Reaffirmed January 2013
- API RP 14H, Recommended Practice for Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore, Fifth Edition, August 2007
- API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, Second Edition, May 2001; Reaffirmed January 2013

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

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

See also, 30 CFR 250.800(d) ("If there are any conflicts between the documents incorporated by reference and the requirements of this subpart, you must follow the requirements of this subpart.").

Other Standards Incorporated by Reference

- ANSI/ASME Boiler and Pressure Vessel Code, Section I, Rules for Construction of Power Boilers; including Appendices, 2004 Edition; and July 1, 2005 Addenda, and all Section I Interpretations
- ANSI/ASME Boiler and Pressure Vessel Code, Section IV, Rules for Construction of Heating Boilers including Appendices 1, 2, 3, 5, 6, and Non-Mandatory Appendices B, C, D, E, F, H, I, K, L, and M, and the Guide to Manufacturers Data Report Forms, 2004 Edition; July 1, 2005 Addenda, and all Section IV Interpretations
- ANSI/ASME Boiler and Pressure Vessel Code, Section VIII, Rules for Construction of Pressure Vessels; Divisions 1 and 2, 2004 Edition; July 1, 2005 Addenda, Divisions 1, 2, and 3 and all Section VIII Interpretations
- API 510, Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration, Downstream Segment, Ninth Edition, June 2006
- API RP 2RD, Recommended Practice for Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), First Edition, June 1998; reaffirmed, May 2006, Errata, June 2009
- API RP 2SK, Recommended Practice for Design and Analysis of Station keeping Systems for Floating Structures, Third Edition, October 2005, Addendum, May 2008
- API RP 2SM, Recommended Practice for Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring, First Edition, March 2001, Addendum, May 2007

- API RP 14F, Recommended Practice for Design, Installation, and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class 1, Division 1 and Division 2 Locations, Upstream Segment, Fifth Edition, July 2008, Reaffirmed: April 2013
- API RP 14FZ, Recommended Practice for Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Zone 0, Zone 1 and Zone 2 Locations, First Edition, September 2001, Reaffirmed: March 2007
- API RP 14G, Recommended Practice for Fire Prevention and Control on Fixed Open-type Offshore Production Platforms, Fourth Edition, April 2007
- API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2, Second Edition, November
- API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2, First Edition, November 1997; Reaffirmed, August 2013
- ANSI/API RP 2N, Third Edition, "Recommended Practice for Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions", Third Edition, April 2015;
- API 570 Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems, Third Edition, November 2009

Appendix 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.

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 Gulf of Mexico 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.

BOE: Barrel Oil Equivalent the amount of energy resource (in this document, natural gas) that is equal to one barrel of oil on an energy basis. The conversion is based on the assumption 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.

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.

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: 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 for the production of 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.

SafeOCS: BSEE and BTS program designation encompassing SPPE, WCR, and ISD.

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

Wellbore: The volume contained within the cross-sectional area of the well tubing, which contains the 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.

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 Gulf of Mexico 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. Well trees are 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.[20]

Acronym and Abbreviation List

ANSI: American National Standards Institute

API: American Petroleum Institute

BOE: Barrels 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

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

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

NTL: Notice to Lessees

OEM: Original Equipment Manufacturer

OCS: Outer Continental Shelf

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

PSSR: Production Safety Systems Rule

RCFA: Root Cause Failure Analysis

FRCA: Formal Root Cause Analysis

SME: Subject Matter Expert

SPPE: Safety and Pollution Prevention Equipment

SSV: Surface Safety Valve

SCSSV: Surface Controlled Subsurface Safety Valve

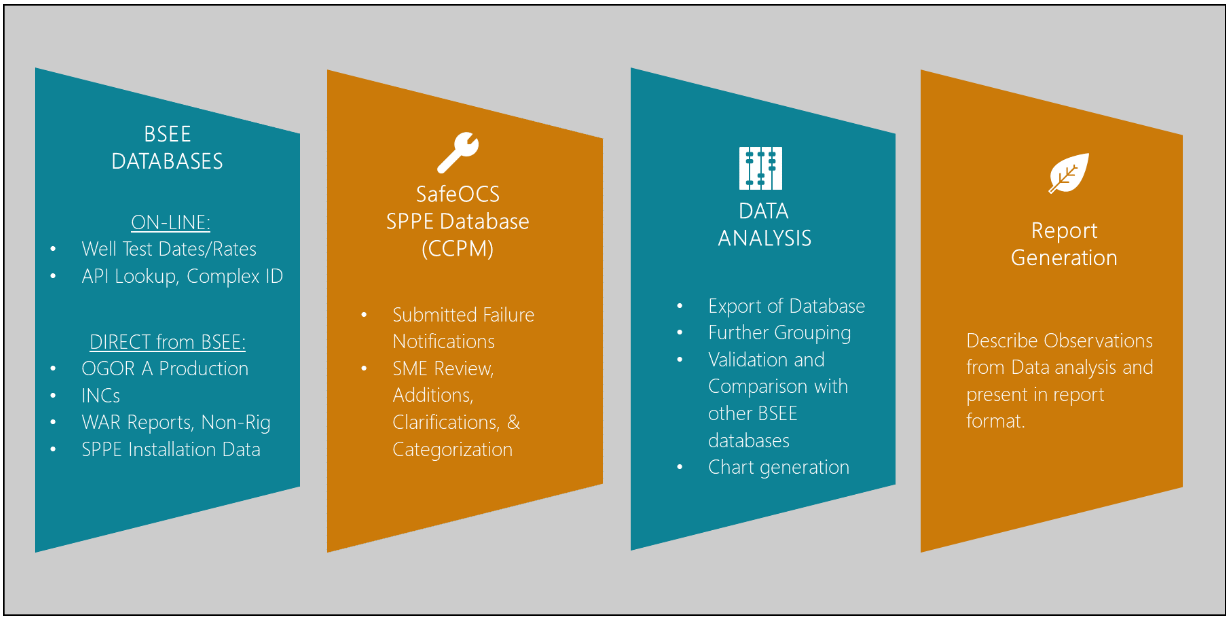
SSCSV: Subsurface Controlled Safety Valves

USV: Underwater Safety Valve

WAR: Well Activity Report

Appendix D: Data Analysis Methodology

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



Age of SPPE from First Production Grouping

Since the installation date of the SPPE was not reported, and the original SPPE on the well may have been replaced since it was first installed, a surrogate "age" was calculated by subtracting the month of the well's first production from the current completion) from the date of failure. It is possible that the SPPE is not as old as the surrogate age, but it is unlikely to be any older than the surrogate age because the well components are generally new at the time of first production (e.g., a new well or re-completed well with new components).

The Well Test and Well Rate

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[21] which require lessees (i.e., operators) to submit well test volume reports at least once every month for each producing completed well. During well testing, the well's fluid

[21] 30 CFR 250.1151(a)(2).

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. In order 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.[22] The 5.62 factor is the number of cubic feet in an equivalent barrel of oil, and is the industry standard to calculate an equivalent gas rate.

If the well test rate was provided in the notification, BTS used that value to determine that well's well rate range. In cases where the last well test was not provided in the notification, BTS used the most recent well test prior to the failure from BSEE's Data Center – "Specified Well Test Detailed Report" as of 2/5/19. 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 and well test rates were only used to validate the well rate range for each well with a reported failure.

The well rate range for each of the producing wells in the 2018 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 2018, and then dividing the sum of those two volumes by the number of days the well was in production in 2018.

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.[23] The following INCs were included in this analysis:

PINC	Number of INCs	Short Description
P412	48	SSV, USV, or BSDV had internal leakage
P241	8	SCSSV failed to close within 2 minutes

[22] 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.
[23] 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.

P280	7	SSV failed to close within 45 seconds
P240	6	SCSSV was not tested every 6 months
P307	5	SSV was not tested monthly
P102	5	Shutdown device did not perform its function when commanded
P319	1	BSDV was not tested monthly
P103	1	SSCSV was not tested every 6 months or 1 year
P281	1	Shutdown device or sensors did not function
Total	**82**	

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 2018 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?

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 ISEACH 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?

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 BSDVs are often associated with multiple wells, no API well number was assigned to those failures.

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, Pacific, and Alaska), reported via Well Activity Reports (WARs) on a weekly basis in the Gulf of Mexico 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 2018 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 intervention. 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 none of the SPPE failures reported to SafeOCS in 2018 were found in the WAR data, there were a total of 16 additional failures identified in the WAR data that were not reported to SafeOCS.

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. BTS refers to this database as the "SPPE Valve Data." 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 Gulf of Mexico. This improved the population estimate and allowed the population to be reported by SPPE type. This data (i.e., installation date) was also used, in some cases, to determine the age of SPPE valve at the time of failure.

BTS considered 12,174 SPPE's as "active SPPE valves" after reviewing the list of 19,278 Safety Valves provided by BSSE, considering the information in the following data fields:

- API Well Number – if the valve indicated an API number, it was considered an SPPE
- Valve type (SSV, SCSSV, etc.) – Included SSV, SCSSV, SSCSSV (aka SSCSV), USV, and BSDV
- Removed Date – excluded valves that had been removed
- Device Description (Title) – excluded valves on equipment other than wells
- Component Code (KAA, MAJ, etc.) – excluded valves on pipelines, vessels, etc. other than wells
- Component Eq Service Description -– excluded wells on pipelines, vessels, etc. other than well
- Component Out of Service Flag -Y/N – excluded those marked as out of service
- Region code (G, P, Y) – excluded those other than G for Gulf of Mexico

Well Count Determination from OGOR-A Data

The total Gulf of Mexico 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 Active Drilling

2 DSI, Drilling suspended

14 TA, temporarily abandoned

15 Completion abandoned

16 PA, permanently 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 2018. The active wells were similarly counted for each operator, in addition to the operators' total production.

Appendix E: 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

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 7). 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 7: Certification Status of Reported SPPE

SPPE Certification	Percent of Reports
Newly Installed certified SPPE pursuant to ANSI/API Spec Q1	12.8
Newly Installed certified SPPE pursuant to another quality assurance program	1.0
Previously certified under ANSI/ASME SPPE-1	74.4
Non-Certified SPPE	0.5
Not Answered	11.3

SSV and BSDV 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, 37.0 percent were Class 1 and 41.8 percent were Class 2. The remaining 21.2 percent of reporters did not specify a class. BSDVs are further categorized as either automatic or manual. All 5 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 34 reported SCSSVs and SSCSVs, ten were Class 1, two were Class 2, one was both Class 1 and Class 2, and four were Class 3s. The remaining 17 did not report the class.