OIL AND GAS PRODUCTION SAFETY SYSTEM EVENTS

2023 Annual Report

U.S. Department of Transportation
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Bureau of Transportation Statistics

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ACKNOWLEDGEMENTS

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EXECUTIVE SUMMARY

The *2023 Annual Report: Oil and Gas Production Safety System Events*, produced by the Bureau of Transportation Statistics, summarizes safety and pollution prevention equipment (SPPE) failures that occurred on oil and gas wells in the Gulf of Mexico (GOM) Outer Continental Shelf (OCS) during the calendar year. This report is based on information collected through SafeOCS, a confidential reporting program for the collection and analysis of data to advance safety in offshore energy operations. It includes an analysis of reported events involving SPPE valves and other key information about the events such as root causes and follow-up actions.

Reporting of SPPE failures to SafeOCS in 2023 was approximately equal to the 2020 to 2022 average reporting levels, with 95 failure notifications submitted to SafeOCS. These events were reported by 13 operators who operate nearly 60 percent of the active wells and contribute 70 percent of the GOM production, which exceeded 2019 (pre-Covid) levels for the first time in 2023. BTS used other data sources (WAR, APM, INCs, OGOR-A, and BSEE incident data) to identify 99 additional SPPE failures during 2023, including 48 failures on wells operated by ten additional operators.[1] In total these operators along with reporting operators were responsible for most (94.6 percent) of the active wells and the production (92.7 percent) in 2023.

Valve Types

Surface safety valves (SSVs) and surface controlled subsurface safety valves (SCSSVs) continued to have the highest proportions of failures in 2023, comprising 63.7 percent and 24.6 percent of failures with known valve type, respectively.[2] Ten failures of SSCSVs were reported to SafeOCS or identified in other sources in 2023, higher than any previous year of the reporting program.

Potential Consequences of Failures

Failures are categorized based on the extent to which they degrade the installed well safety systems and pose potential consequences to personnel and the environment. The 2023 failures within each of the more significant event types include no HSE events. Three small external leaks of hydrocarbons from surface valves were reported, two found during initial start-up testing, and one found during a planned facility shutdown. Twenty of the reported events involved failures to close, meaning the valve would not be effective in controlling the well flow if called upon, and 13 events involved failure to close in the

[1] APM—Application for Permit to Modify; INC—Incident of Noncompliance; OGOR-A—Oil and Gas Operations Report – Part A; WAR—Well Activity Report.
[2] Percentages are of 179 total failures. Excludes 15 failures of subsurface safety valves identified in OGOR-A data or other sources where it could not be determined whether they were SCSSVs or SSCSVs.

required timing. Most SPPE failures (65.6 percent), where information on the event type was available, were categorized as internal leaks, meaning the valve closed but failed to seal, allowing some fluid to flow through it.[3]

Characteristics of Wells with SPPE Failures

Most (93.0 percent) of the known SPPE failures occurred on wells that produced at least one day in 2023, as opposed to nonproducing wells.[4] Thirty-two (32) of the 185 events involving a single well (17.3 percent) occurred on wells producing more than 500 barrels of oil equivalent per day (boed), and 16 (8.6 percent) were on single wells producing over 1,000 boed.[5] Six failures that were on wells producing over 1,000 boed involved failures of the valve to close when commanded, five of which involved SCSSVs. In 2023, wells with highest gas-oil ratio (GOR) (15,000 cf/bbl and above) experienced more failures than expected based on the population of wells in that GOR range.

Root Causes and Contributing Factors of Failures

As with previous years, wear and tear was the most frequently reported root cause, listed for 83.1 percent of surface valve failures and 22.2 percent of subsurface valve failures reported to SafeOCS. Fifteen of the 77 surface valve failures reported to SafeOCS were SSVs that failed within 12 months of installation or a qualifying repair with a stated root cause of wear and tear. Nine of the 15 failures were determined to be repeated failures, meaning the same component failed on the same valve within 12 months. Design issue was the most frequently reported root cause of subsurface valve failures submitted to SafeOCS, reported for five subsurface valve failures (27.8 percent).

[3] Percentage considers events where internal leak was the most significant failure type reported.
[4] Percentage is of failures that occurred on single wells with a known API well number. Well rates in barrels of oil equivalent (boed) per day based on the average production in the 12 months preceding the failure.
[5] Well rates in barrels of oil equivalent (boed) per day based on the average production in the month prior to the failure.

1 Introduction

The *2023 Annual Report: Oil and Gas Production Safety System Events*, produced by the Bureau of Transportation Statistics (BTS), provides information on safety and pollution prevention equipment (SPPE) failures reported to SafeOCS during the calendar year. These failures occurred during oil and gas production operations in the Gulf of Mexico (GOM) Outer Continental Shelf (OCS). Per 30 CFR 250.803, operators must submit a failure notification to SafeOCS when a specific SPPE valve does not perform as designed. This annual report includes an overview of the types of failures reported, characteristics of the wells with SPPE failures, and root causes and contributing factors.

About SafeOCS

SafeOCS is a confidential reporting program for collecting and analyzing data to advance safety in energy operations on the OCS. The objective of SafeOCS is to capture and share essential information across the industry about accident precursors and potential hazards associated with offshore operations. The program is sponsored by the Department of the Interior's Bureau of Safety and Environmental Enforcement (BSEE) and operated independently by the Department of Transportation's Bureau of Transportation Statistics (BTS), a principal federal statistical agency. The Confidential Information Protection and Statistical Efficiency Act (CIPSEA) protects the confidentiality of all data submitted directly to SafeOCS.[6]

The SafeOCS program umbrella comprises several safety data collections, including the SPPE failure reporting program, which is the subject of this report. Under 30 CFR 250.803, operators must follow the SPPE failure reporting procedures in specified API standards and submit failure reports to both BTS, as BSEE's designated third party to receive this information, and the original equipment manufacturer.[7] This is the seventh annual report on the SPPE failure reporting program.

Contributors to this report include subject matter experts retained by BTS to provide technical knowledge in production operations, subsea engineering, equipment testing, well equipment design and manufacturing, root cause failure analysis, quality assurance and quality control, and process design. They reviewed event and investigation reports, reviewed BTS and BSEE data, and contributed to analyses of aggregated data.

[6] Confidential Information Protection and Statistical Efficiency Act of 2018, Title III of the Foundations for Evidence-Based Policymaking Act of 2018, Pub. L. No. 115-435.
[7] See appendices A and B for additional detail on the regulatory requirements for SPPE failure reporting.

Data Adjustments

- SafeOCS may receive SPPE event notifications after the publication of annual reports. If notifications are received after publication that meaningfully impact this report's results and conclusions, an addendum may be published.

- Numbers are adjusted in each annual report to reflect information provided after publication and may vary from those reported in the previous annual report. All reported results and references to previous data in this report represent updated numbers unless otherwise stated.

- Over time, data analysis methods may change to improve data accuracy and better characterize the aggregate data. Any changes to data analysis methods are noted in this report and the results reflect the current methodology.

- Due to rounding, numbers in tables and figures may not add up to totals.

2 SAFETY AND POLLUTION PREVENTION EQUIPMENT (SPPE)

In general, SPPE promotes the safety and protection of human, marine, and coastal environments. The specific SPPE covered by the Oil and Gas Production Safety Systems Rule (subpart H)[8] protect personnel and the environment by controlling the flow of well fluids (crude oil, natural gas, and water), especially in case of an emergency or system failure. The SPPE consists of specifically designated safety valves, actuators, and their control systems, which are required by BSEE regulations, industry standards, and in most cases, company policies. SPPE includes the following valve types:[9]

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

SPPE valves are operated in the open position to allow produced fluids from the well to flow. They are designed to close automatically if a control system failure occurs (i.e., fail-safe valves) or if there is an operational need to stop the flow from the well. All SPPE valves are considered isolation valves and mechanical barriers because they are designed to stop the flow of well fluids to protect personnel, equipment, and the environment. In general, the main valve component moves from an open to a closed position, where it contacts the valve seat to seal off the internal flow in the pipe or tubing. All SPPE valves, excluding the SSCSVs, are automatically operated, meaning a hydraulic or pneumatic actuator is used to open or close the valve. SPPE valves can be opened or closed for routine operations by the operator from the platform control system. More information about the operation of SPPEs is provided in Appendix E.

All SPPE valves must be function tested and leak tested per the requirements of subpart H.[10] Table 1 summarizes the general testing frequencies and leakage requirements. However, exceptions can apply for different types of wells, subject to BSEE's approval.[11]

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[8] The rule is codified primarily in 30 CFR part 250, subpart H. The failure reporting requirement is codified in 30 CFR 250.803.
[9] 30 CFR 250.801.
[10] 30 CFR 250.873, 250.880.
[11] Additional information and requirements for new wells and wells that are completed and disconnected from monitoring capability are provided in the CFR.

Table 1: Typical SPPE Testing Frequency and Leakage Allowance

Valve	Allowable Leakage Rate	Testing Frequency
Surface Valves		
SSV	Zero leakage	Monthly, not to exceed 6 weeks
BSDV	Zero leakage	Monthly, not to exceed 6 weeks
GLSDV	Zero leakage	Monthly, not to exceed 6 weeks
Subsurface Valves		
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.
USV	400 cc per minute of liquid (oil or water) or 15 scf per minute of gas	Quarterly, not to exceed 120 days

KEY: cc (or cm3)—cubic centimeters, scf—standard cubic feet.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

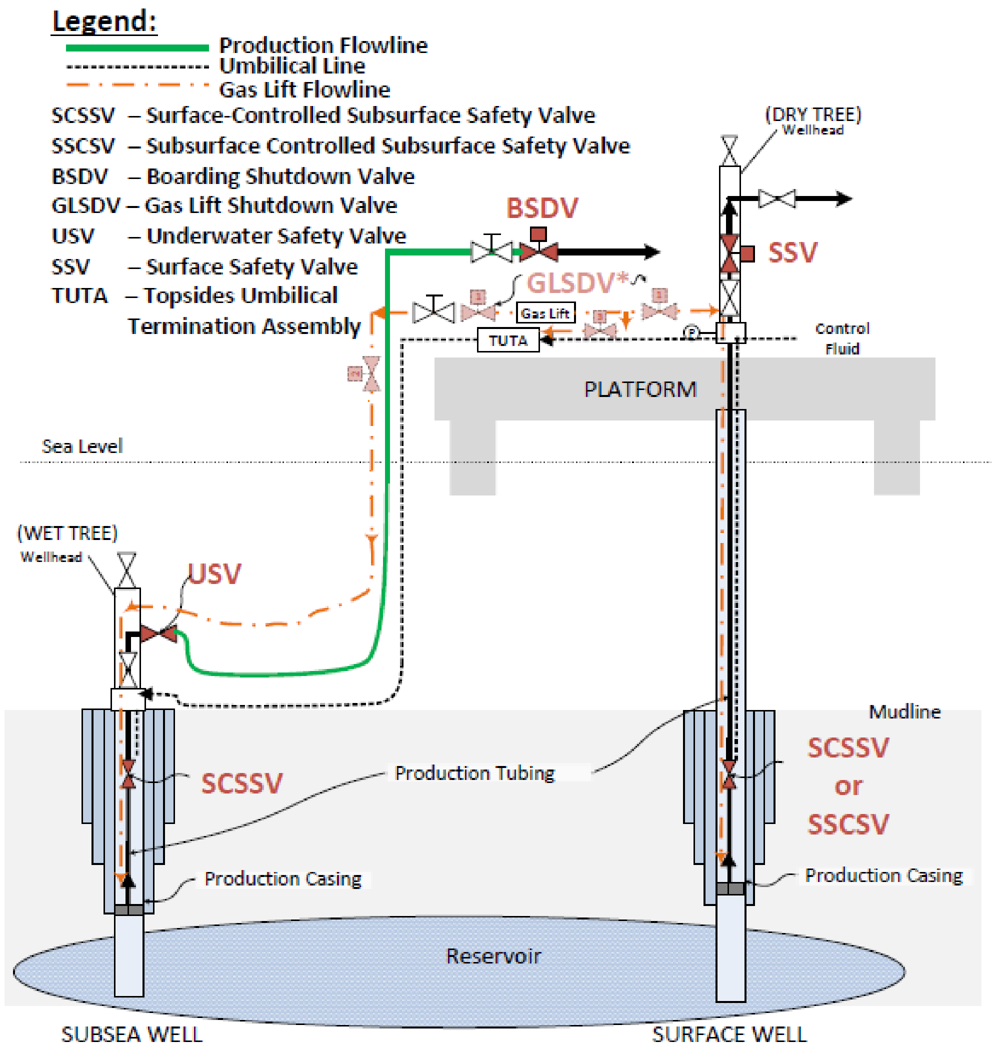
Location of SPPE Valves

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

A typical surface well is equipped with at least one subsurface safety valve (SCSSV or SSCSV) in the tubing below the seafloor (mudline) and an SSV on the wellhead. Similarly, a subsea well is equipped with at least one subsurface safety valve and a USV. However, SSCSVs are no longer allowed by BSEE in new subsea wells due to reliability issues and long repair times caused by the need for an intervention vessel. Per subpart H, a production master valve (PMV) or production wing valve (PWV) may qualify as a USV under API Spec. 6A and API Spec. 6AV1.[12] They provide 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.

[12] 30 CFR 250.833.

Figure 1: Equipment Schematics



NOTE: GLSDVs for subsea wells may be installed in one of three alternate locations as described in 30 CFR 250.873: (1) horizontal valve on gas lift supply line within 10 feet of the platform edge; (2) vertical valve in gas lift supply line riser run within 10 feet above the first accessible working deck (excluding the boat landing and splash zone); (3) gas lift supply via umbilical within 10 feet of the TUTA.
SOURCE: U.S. Department of Energy, Office of Science, Argonne National Laboratory.

How Valve Types Are Grouped in this Report

SPPE valves are often grouped in this report as either *surface* (SSV, BSDV, and GLSDV) or *subsurface* (SCSSV, SSCSV, and USV) to evaluate potential patterns or trends based on valve location (on-platform versus below the waterline). Although USVs are typically not considered subsurface valves, as the latter generally refers to valves installed below the mudline, USVs are included with subsurface valves because they are installed below the water's surface.

3 DATA COLLECTION AND VALIDATION

Data Confidentiality—CIPSEA

The Confidential Information Protection and Statistical Efficiency Act (CIPSEA)[13] protects the confidentiality of all data submitted directly to SafeOCS. Data protected under CIPSEA may be used only for statistical purposes. This provision means that BTS can publish only summary statistics and data analysis results; incident microdata collected by SafeOCS may not be shared or used for any nonstatistical purpose, including any administrative, regulatory, law enforcement, adjudicative, or other purpose. Information submitted under this statute is protected from release to other government agencies, including BSEE, and from Freedom of Information Act (FOIA)[14] requests.

To provide proof of an operator's compliance with the reporting regulation—without sharing the details of the event, which are CIPSEA-protected—the following information is shared with BSEE via an automated email following receipt of an event notification: submittal date, company identification, and event reference number.

Data Validation and Exposure Measures

BTS used data provided by BSEE to validate SafeOCS data and develop exposure measures that help provide context for the failures. BTS validated submitted data by reviewing additional BSEE data sources that contained information about the failure event or characteristics of the well with the failed SPPE. These data sources were also used to identify SPPE failure events that were not reported to SafeOCS.

BTS used BSEE data sources to develop exposure measures that quantify the population of SPPE that could be called upon to perform functional specifications of that population. These exposure measures, sometimes referred to as denominator or normalizing data because they represent the population in terms of statistical values, facilitate comparison among different types of SPPE and well environments. The specific BSEE data sources are listed below. Appendix D provides more information about each data source and the methods used in evaluating it.

The following data sources were used to identify SPPE failure events or provide supplemental information for failure events reported to SafeOCS:

- Applications for Permit to Modify (APMs)

[13] Confidential Information Protection and Statistical Efficiency Act of 2018, Title III of the Foundations for Evidence-Based Policymaking Act of 2018, Pub. L. No. 115-435.
[14] 5 USC 522.

- Well Activity Reports (WARs)
- Incidents of Noncompliance (INCs)
- Incident Reports
- Oil and Gas Operations Reports – Part A (OGOR-A)

The following data sources were reviewed for well information and in developing exposure measures:

- Oil and Gas Operations Reports – Part A (OGOR-A)
- SPPE Installation Data
- Well Test Reports
- Borehole and API Well Number Data

4 Data Analysis

SPPE Numbers at a Glance

The Oil and Gas Production Safety Systems Rule[15] covers production operations on the Outer Continental Shelf (OCS), which includes BSEE's Gulf of Mexico (GOM), Pacific, and Alaska regions. As in prior years, in 2023 SafeOCS received equipment failure notifications for operations in the GOM region only, which accounts for over 99 percent of all offshore production in the United States.[16] To protect confidentiality, the exact locations of reported equipment failures are not disclosed.

SafeOCS received 95 SPPE failure notifications for 2023, a 37.7 percent increase from 2022. An additional 99 failure events were identified in other sources (APM, INC, OGOR-A, WAR, or BSEE incident data), bringing the total number of known SPPE failure events in 2023 to 194, a 26.8 percent increase from 2022. To the extent practicable, analyses presented in this report consider failure events identified in all sources; however, failures not directly reported to SafeOCS are excluded from some analyses due to less complete information about the events. Each figure or table is annotated with an explanation of which failure events are included.

Table 2 provides an overview of the reported SPPE failures in 2023 compared to the previous six years. The 95 failures occurred on 90 of 4,254 total active wells (2.1 percent) in the GOM OCS.[17] Most of those failures (91.6 percent) were on valves accessible from the platform where they can be addressed more quickly, reducing potential safety and environmental risk.[18] There were three leaks of hydrocarbons to the atmosphere in 2023, the same number as in 2022, but none were large enough to be considered an HSE event.

As shown in Table 2, the number of active wells continued to fall in 2023, while well production increased. The number of operators who reported failure notifications to SafeOCS increased from 11 in 2022 to 13 in 2023, discussed further in the section titled *Who Reported Equipment Events*. Operators reporting to SafeOCS were responsible for nearly 60 percent of active wells and 70 percent of production in 2023.

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[15] 30 CFR 250 subpart H.
[16] BSEE Data Center, Outer Continental Shelf Oil and Gas Production data, 2023 annual volumes.
[17] For purposes of this report, an active well is considered a well completion with SPPE valves providing a barrier to the fluids in the reservoir. A well was counted as active if it had an OGOR-A status code other than drilling, abandoned, or well work for at least one month of the year.
[18] Includes failures on surface wells, plus failures of GLSDVs and BSDVs associated with subsea wells.

Table 2: SPPE Numbers at a Glance

	2017	2018	2019	2020	2021	2022	2023
Operator Summary[1]							
Active Operators	56	55	52	45	43	39	40
Producing Operators	53	50	49	42	41	38	37
Reporting Operators	8	14	14	14	14	11	13
Pct. Reporting Operators	14.3%	25.5%	26.9%	31.1%	32.6%	28.2%	32.5%
Reporting Operators' Pct. of Active Wells	35.2%	70.6%	59.4%	58.0%	64.9%	45.1%	59.9%
Reporting Operators' Pct. of Production	56.6%	66.6%	75.7%	57.8%	73.9%	29.3%	70.0%
GOM Well Production Summary[2,3,4]							
Active Wells	6,446	6,231	6,029	5,715	5,402	4,613	4,254
Wells with SPPE Failure	96	157	182	90	114	59	90
Pct. Wells with SPPE Failure	1.5%	2.5%	3.0%	1.6%	2.1%	1.3%	2.1%
Daily Prod. of Total Active Wells (boed)	2,207,312	2,243,244	2,741,291	2,414,434	2,738,538	2,730,825	2,791,301
Daily Prod. of Wells with SPPE Failure (boed)	20,028	56,174	71,289	70,928	107,649	67,780	44,337
Pct. of Daily Prod. of Wells with SPPE Failure	0.9%	2.5%	2.6%	2.9%	3.9%	2.5%	1.6%
SPPE Failure Summary[5]							
Total Distinct SPPE Failures	215	266	351	172	214	153	194
SPPE Failures Reported to SafeOCS	**115**	**204**	**225**	**101**	**114**	**69**	**95**
SPPE Failures Identified from Other Sources	100	62	126	71	100	84	99
Pct. of Failures Not Reported to SafeOCS	46.5%	23.3%	35.9%	41.3%	46.7%	54.9%	51.0%
Repeated Failures Reported to SafeOCS	N/A	13	14	13	12	11	10
Tree Types (SafeOCS Failures Only)							
Surface Well SPPE Failure Events	109	195	210	93	91	57	78
Subsea Well SPPE Failure Events	4	8	15	8	21	10	14
SPPE Failure Events with Unknown Tree Type	2	1	0	0	2	2	3
Event Types (SafeOCS Failures Only)[6]							
HSE Incident	0	0	0	0	0	0	0
External Leak of Hydrocarbons	1	2	5	3	1	3	3
Failed to Close When Commanded	13	16	22	11	10	8	14
Internal Leak	99	159	199	80	93	55	68
Failed to Close in Required Timing	0	14	0	1	1	0	2
Failed to Open	3	6	5	4	5	3	9
External Leak of Other Fluids	1	11	5	4	5	3	2

KEY: APM—Application for Permit to Modify; BTS—Bureau of Transportation Statistics; GOM—Gulf of Mexico; HSE—Health, Safety, and Environment; INC—Incident of Noncompliance; OGOR-A—Oil and Gas Operations Report – Part A; Pct.—percent; SPPE—Safety and Pollution Prevention Equipment; WAR—Well Activity Report.

NOTES:

1 Active operator counts have been updated to reflect company mergers and acquisitions. An active operator is one with active wells in the GOM.

2 A well was counted as active if it had an OGOR-A status code other than drilling, abandoned, or well work for at least one month of the year. In 2020, BTS began counting wells by API number and completion interval. Previously, multiple well completions with the same API number were counted as one well. Previous year totals have been updated to reflect the revised methodology.

3 "Wells with SPPE Failure" and "Daily Prod. of Wells with SPPE Failure" consider only failures reported to SafeOCS.

4 The number of installed SPPE valves was included in previous annual reports but is not included here. BTS and BSEE are

reviewing the available data and methods for determining the SPPE valve population to ensure accuracy.

5 For 2017 and 2018, other sources include INC and WAR data. OGOR-A data was added in 2019, APM data was added in 2020, and BSEE incident data was added in 2021.

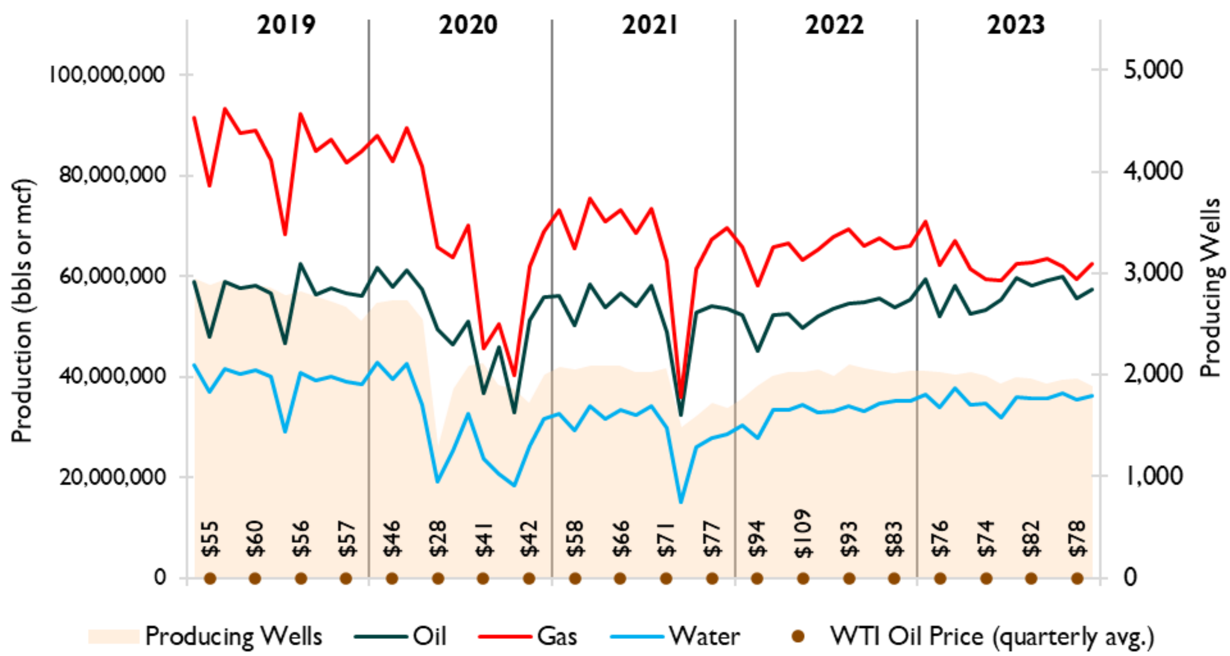
6 Totals may exceed counts of SafeOCS failures because more than one event type can apply to a single failure. Failures identified in other sources that are not reflected in this table include two HSE events involving releases of hydrocarbons to the sea, one in 2020 and one in 2022.

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

Production Levels in 2023

Monthly oil, gas, and water volumes produced in the GOM are shown as trend lines in Figure 2. The shaded area in the same figure indicates the number of wells that were producing each month. In 2023, oil production levels increased overall while gas production and the number of producing wells declined slightly. The COVID-19 pandemic contributed to increased variability in these measures in 2020 and 2021, as did hurricane and tropical weather events in the GOM during August and September 2021. Storms appear to have had less of an impact on production in 2022 and 2023. Total production (boe) for 2023 exceeded pre-COVID levels for the first time since the pandemic, by 1.8 percent.

Figure 2: GOM Production, 2019-2023

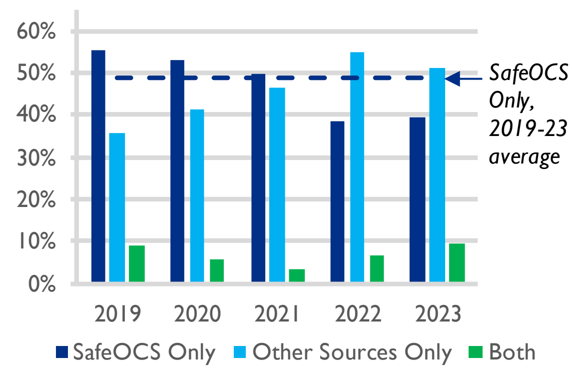


SOURCES: U.S. DOT, BTS, SafeOCS. WTI crude oil spot prices from U.S. Energy Information Administration.

Completeness of Failure Event Reporting

In addition to failures reported directly to SafeOCS, BTS evaluated other BSEE data sources including APM, INC, OGOR-A, WAR, and BSEE incident data to develop a larger set of records for failure events that occurred in the GOM OCS during operations. Figure 3 shows the overlap between the failures reported to SafeOCS and those identified in other sources. For 2023, 194 distinct SPPE failures were reported or identified in available data, including 77 (39.7 percent) reported to SafeOCS only, 99 (51.0 percent) not reported to SafeOCS, and 18 (9.3 percent) both reported to SafeOCS and found in the other sources. Therefore, reporting of SPPE failures to SafeOCS appears to remain incomplete, increasing slightly from 45.1 percent in 2022 to 49.0 percent 2023. The findings for each of the additional data sources are described in more detail below.

Figure 3: Sources of SPPE Failure Records, 2019–2023



NOTE: Other sources include APM, INC, OGOR-A, WAR, and BSEE reported incident data.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

APM Data

APM data and WAR data usually complement one another as WAR reports describe the well work that happens after an APM is approved. Consequently, the number of failures identified in the analysis of the 2023 APM (32) is almost the same as the number of failures identified in WAR (33). The 32 events include 14 SCSSVs, 12 SSVs, four SSCSVs, one USV, and one subsurface safety valve where it was unclear whether the replaced SPPE was an SCSSV or an SSCSV. Nine of these failures were also reported to SafeOCS, and eight of those nine were also found in WAR data. Failures found in APM data remained relatively consistent from 2020 to 2022 at approximately 15 to 18 failures per year; however, failures found in APM data for 2023 were approximately double that amount (32). The increase was driven primarily by an increase in SSV failures identified in APM data, from approximately zero to four annually in previous years to 12 in 2023.

WAR Data

The events identified in WAR in 2023 include 15 SCSSVs, 13 SSVs, three SSCSVs, one USV, and one subsurface safety valve where it was unclear whether the replaced SPPE was an SCSSV or an SSCSV. The number of SSVs found in WAR also increased compared to 2022, from five to 13, ten of which were also found in APM. Eight of the failures identified in WAR data were also reported to SafeOCS, comprising six SCSSVs and two SSVs. As WAR and APM data are related sources, 29 of the 33 failures identified in WAR data in 2023 were also found in APM data. Failures found in both WAR and APM data could mean that the repairs were planned as opposed to discovered during intervention work. However, determining the cause of these failures is difficult as the available data is limited to the operational repair activities rather than the valve operating history.

WAR data may also include preventive maintenance reports, such as the required removal of a valve for testing. Importantly, BTS distinguishes between preventive maintenance reports and failure events when evaluating the WARs, and the events identified in WAR data represent only failure events, as described below:

- SCSSV events: In two cases, a plug was set in the well, and in one of those cases the plug was set after multiple attempts to install a wireline-retrievable SCSSV (FXE) valve. In three cases, the existing SCSSV was "locked open" or removed and a PB valve was installed. In three cases, a wireline-retrievable SCSSV (FXE) was installed in the well. In two cases, the SCSSV was replaced with a different model, and in one case the SCSSV was replaced in kind. In three SCSSV cases, chemical soak was performed.
- SSCSV events: In three cases, the existing PB valve was replaced and one PB valve was repaired.
- Other events: In the 13 SSV cases, six SSVs were repaired, five were replaced, and the actuator was repaired on two. In the USV case, the USV was repaired.

INC Data

In 2023, failures found via analysis of the INC data were about the same as in 2022 (61 vs. 57 in 2022 and 2023, respectively). The SPPE failures identified in the INC data included 32 SSVs, 18 SCSSVs, four SSCSVs, two GLSDVs, and one USV. Nine of these failures were also reported to SafeOCS, and one was found in APM and WAR. Importantly, the number of INCs involving SPPE valves represents only those failures occurring while BSEE is visiting the platform (i.e., a subset of all failures). Additional detail on the failures identified in INCs is included in Appendix D.

OGOR-A Data

A total of 22 SPPE failures were documented in the 2023 OGOR-A data, compared to 13 in 2022 and 39 in 2021. None of these failures were reported to SafeOCS. The 22 failures identified in OGOR-A data include 14 subsurface safety valves (OGOR-A does not distinguish between SCSSVs and SSCSVs), seven SSVs, and one SSCSV (where the valve type information was found in WAR data when the valve was replaced).

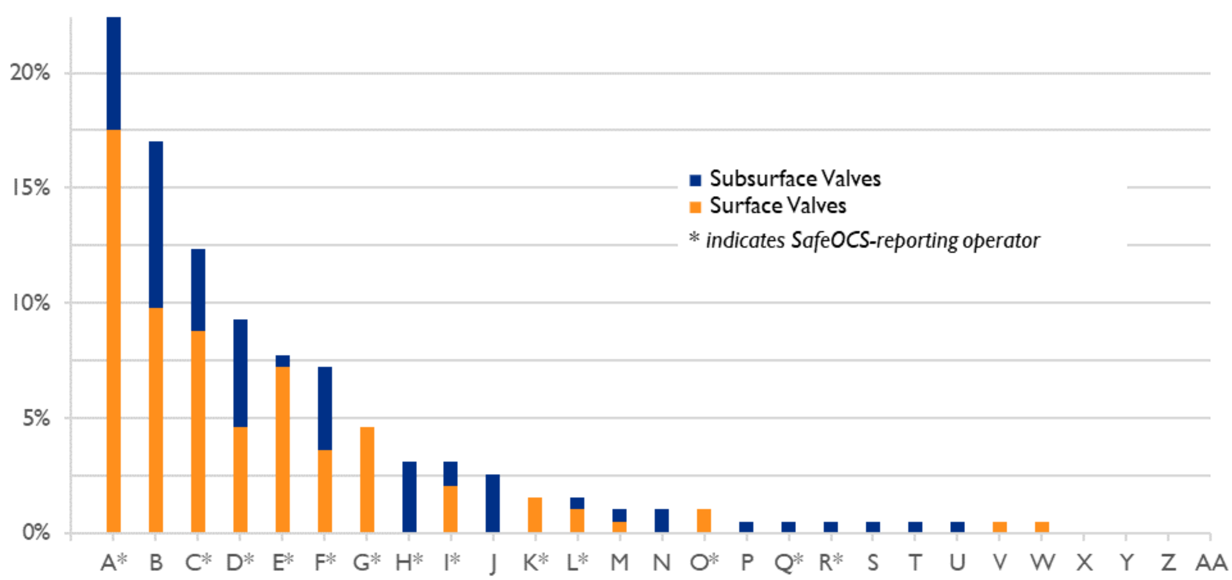
Incident Reports

Three SPPE failure events were identified among BSEE investigated incidents in 2023. These events involved an SCSSV failing to close after a facility ESD for a non-emergency. These events are discussed further on page 24.

Who Reported Equipment Events

Changes in which operators report SPPE events to SafeOCS can occur from year to year due to company consolidations, changes in ownership, or other reasons. Figure 4 shows each active operator's contribution to 2023 SPPE reported failures and the breakdown between surface and subsurface valve events. Each lettered column represents an active operator, i.e., one with active wells in the GOM. Thirteen operators, noted by an asterisk next to the letter, reported at least one 2023 failure directly to SafeOCS. These operators contributed 59.9 percent of active wells and 70.0 percent of production volumes in 2023. Failures for the remaining operators shown in the figure were identified in other data sources (e.g., BSEE WAR data). In 2023, there were five non-reporting operators with greater than one percent of the active wells, but four of these operators did report failures in other data sources evaluated by BTS and had reported to SafeOCS in one or more prior years.

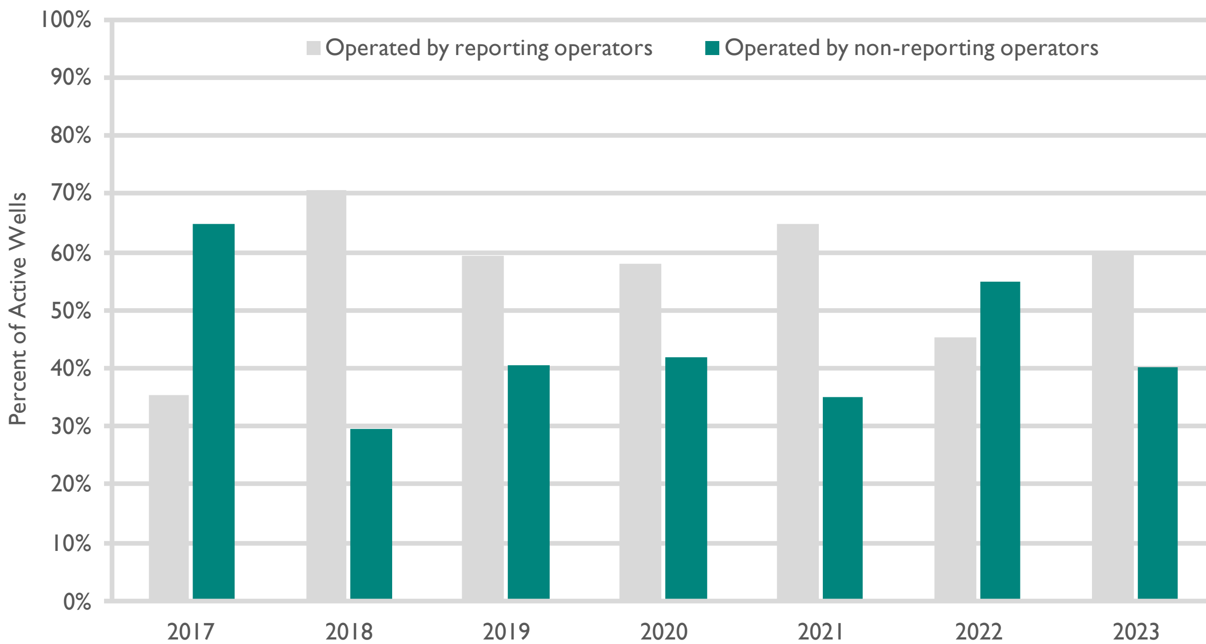
Figure 4: SPPE Failure Events by Operator, 2023



NOTE: Percentage is of 194 failures from all sources. Each column represents an active operator who contributed at least one percent of GOM total production or active wells. Thirteen lower- or non-producing operators with no reported failures are not shown.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Figure 5 shows the distribution of active wells between operators who reported at least one failure to SafeOCS and operators with no reported failures. The percent of active wells attributable to reporting operators increased from 45.1 percent in 2022 to 59.9 percent in 2023. Considering failures identified in other sources in addition to SafeOCS (SafeOCS, WAR, APM, INCs, OGOR-A, and BSEE incident data), the number of operators with at least one identified failure increases from 13 to 23, and these operators were responsible for 94.6 percent of active wells in 2023.

Figure 5: Active Wells and Reporting Status of Operators, 2017-2023



NOTE: Includes only failures reported to SafeOCS.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Details of Reported Equipment

Valve Types

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

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

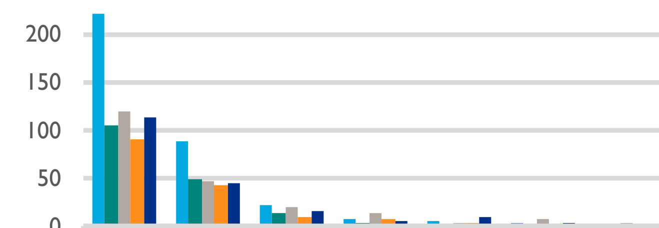
As shown in Figure 6, most SPPE failures since 2019 have occurred on SSVs and SCSSVs, which are the most common SPPE valve types. Figure 7 shows the distributions of the 2023 failures by valve type. SSVs and SCSSVs had the highest proportions of the SPPE failures, collectively comprising 88.3 percent of failures with known valve types in 2023.

The number of failures identified for one valve type versus another is influenced by both the required testing frequency and the accepted leakage rate, which vary between valve types (see Table 1 for testing requirements). If a valve type has a higher required testing frequency or lower allowable leakage rate, more failures may be identified than for other valve types.

Valve Failure Rates

In previous years, valve failure rates were calculated by comparing the number of failure events to the number of installed valves in the GOM, adjusted based on the required testing frequency for each valve type. Valve failure rates are not included here due to current efforts by BTS and BSEE to review the available sources of data on valve population for improved accuracy. An addendum to this report will be

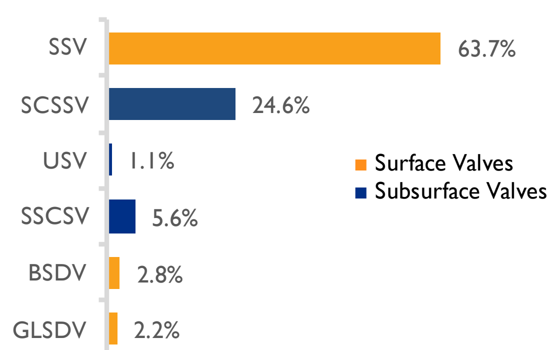
Figure 6: SPPE Events by Valve Type, 2019–23



	SSV	SCSSV	SSSV*	BSDV	SSCSV	GLSDV	USV
2019	221	89	22	8	6	3	2
2020	105	48	13	4		2	
2021	119	47	20	14	4	7	3
2022	90	42	9	7	3	1	1
2023	114	44	15	5	10	4	2

NOTE: Includes failures from all sources. *SSSV = subsurface safety valve failures identified in other sources where it could not be confirmed whether they were SCSSVs or SSCSVs. These SSSV events are not included in the plot below (Figure 7).
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

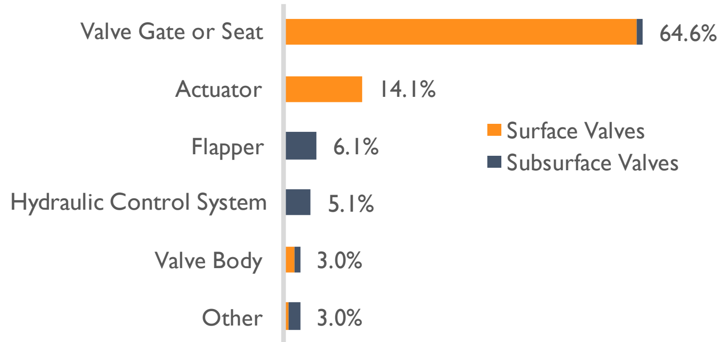
Figure 7: Percentage of SPPE Events by Valve Type, 2023



NOTE: Includes 179 total failures. Excludes 15 failures of subsurface safety valves identified in other sources where it could not be confirmed whether they were SCSSVs or SSCSVs.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

published following the conclusion of that work.

Figure 8: Failed Components in SPPE Valves, 2023



NOTE: Percentage is of 99 failures where the failed component was known to BTS. Total exceeds 100 percent because more than one component may be reported for a single event.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Valve Components

Multiple components make up each SPPE valve.[19] In 2023, the failed component was identified for 99 failures, including 91 reported to SafeOCS and eight identified in other sources. In total, 102 failed components were reported for the 99 events (more than one failed component may be reported for a single event). As shown in Figure 8, the most common component failure for surface valves was the valve gate or seat, comprising nearly two-thirds of the 99 failures. These were followed by the actuator, then the valve body. For SCSSVs, the flapper was the most reported failed component, followed by the hydraulic control system.

Failures of certain components could have a higher consequence than others. For example, one event involving the valve body was an external leak of hydrocarbons due to corrosion on an SSV valve body flange. Another SSV event involving the valve body was an internal leak, citing internal pitting corrosion. Flappers and valve gates and seats, on the other hand, are internal components, so if they fail to seal leakage would be contained internally. For three failures, more than one failed component was reported:

- In one case, both the valve gate and seat and the actuator were listed on a GLSDV failure report of internal leakage. The gate and seat were replaced, and during the post-repair testing the valve actuator was also found defective.
- In one case, the SSV valve gate and seat was listed along with the Emergency Shutdown System (ESD). The failure was detected during testing. No further information was provided as to the how the ESD was involved in the event.
- In one case, the SSCSV valve body and safety lock were listed. Scale and paraffin were noted as contaminants.

The three failures listing "Other" component types include two SCSSVs reporting that asphaltenes

[19] Appendix F lists SPPE valves and their corresponding components.

affected the flow tube in one case and the lower dynamic seal in the other. The third event involved a BSDV with a small external leak (three ounces of condensate with associated produced gas) at the valve stem/actuator, and the stem and bonnet o-ring seals were replaced.

Failures and Potential Consequences

The event type of a reported SPPE failure is an indicator of its potential consequences, i.e., the extent of degradation of installed well safety systems and impacts to personnel and the environment. In 2023, the event type was identified for 157 failures, including 95 reported to SafeOCS and 62 identified in other sources. The remaining 37 events with unknown event type were identified in either OGOR-A (22), WAR (two), APM (one), or more than one of those sources (12) and did not provide enough information to determine the event type. The types of reported SPPE failures are described below in order of significance and shown in Figure 9.

- **HSE Incident**: No SPPE events were reported to SafeOCS or identified in other sources as HSE incidents in 2023.
- **External Leak of Produced Hydrocarbons**: Three events were classified as external leaks of hydrocarbons, two involving a small leak of produced fluids from the SSV or BSDV valve stem/bonnet, which were repaired. A third event involved a small leak from the SSV valve flange, and the valve was replaced.
- **Failure to Close when Commanded:** This event type means the SPPE valve failed to close, so it would not be effective in controlling the well flow if called upon. Twenty such failures were reported, which was four more than in 2022, and these are summarized in Table 3. Additional context is provided in Figure 13, where the failure types are plotted against the well production.
- **Internal Leak**: This event type means the valve closed but failed to seal, allowing some fluid to flow through it. Surface valves are allowed zero leakage, and SCSSVs are allowed 400 cc per minute of liquid (oil or water) or 15 scf per minute of gas. One hundred three (103) such failures were reported, comprising 87 surface valves (81 SSVs, two BSDVs, and four GLSDVs) and 16 subsurface valves (15 SCSSVs and one SSCSV).
- **Failure to Close in Required Timing**: This event type means the SPPE valve failed to close in the required timing of two minutes for subsurface valves and 45 seconds for surface valves, so it would be delayed in controlling the well flow if called upon.[20] Six SSVs and seven SCSSVs failed to close in the required timing. The seven SCSSVs were noted in a single INC and were

[20] The requirement for the SCSSV is to close within two minutes after the ESD signal has closed the SSV for the well.

corrected during the same inspection.

- **Failure to Open**: This event type means the SPPE valve failed to open, so that well fluids could not flow through the tubing or piping. In cases of failure to open, the valve is still capable of performing its safety function of controlling the well flow. Eleven such failures were reported, including seven SCSSVs, one SSCSV, one USV, one SSVs, and one BSDV.
- **External Leak of Control or Other Fluids**: This event type means the SPPE valve allowed a loss of primary containment of fluids other than produced oil or gas, such as hydraulic fluid, instrument air, instrument gas, or other fluids, while the valve is still operable. Note that external leaks of control or other fluids that also involve a failure to open or failure to close on command are shown in Figure 9 as the event type with the highest potential consequence. One leak of instrument air and oil residue was reported on an SSV actuator.
- **Other:** This event type applies when the type of failure is known but does not fit into any of the categories above. In 2023, there were five such events found in other sources and not reported to SafeOCS. Three of the five failures, including two SSVs and the control line for an SCSSV, mentioned a leak, but there was not sufficient description of the event to determine whether the leak was internal or external. One of the five failures involved an SSV actuator with heavy internal corrosion to the point of mechanical damage to the actuator housing; however, the valve continued to function without leakage. The final case was unexpected pressure in the control line for an SCSSV, which was not an external leak and did not meet the definition above for an internal leak.

Table 3: Events Involving Failure to Close when Commanded, 2023

SPPE Type	Number of Events	Description	Corrective Action
BSDV	**1**	**Flowline BSDV failed to close due to broken spring in actuator**	**Repair – replace spring**
SCSSV	**1**	**Failed to close when commanded for leakage test to return to service after a planned shutdown**	**Chemical soak, wireline scratching, and shut-in well**
	1	**Failed to close when commanded for leakage test following an acid stimulation**	**Cycle valve and change flowing conditions**
	3	**Failed to close during a facility ESD for a non-emergency**	**Correct the ESD logic that prevented the valves from closing**
	3	Failed to close when commanded during scheduled leakage test	One replaced with a DX plug, one chemical soak and wireline scratching, and one cycled valve and change flowing conditions
SSCSV	4	PB valve failure identified when pulled for inspection	Two replace, one repair – seat and lock ring, one unknown
	1	PB valve failed in-situ test after installation after inspecting	Replace

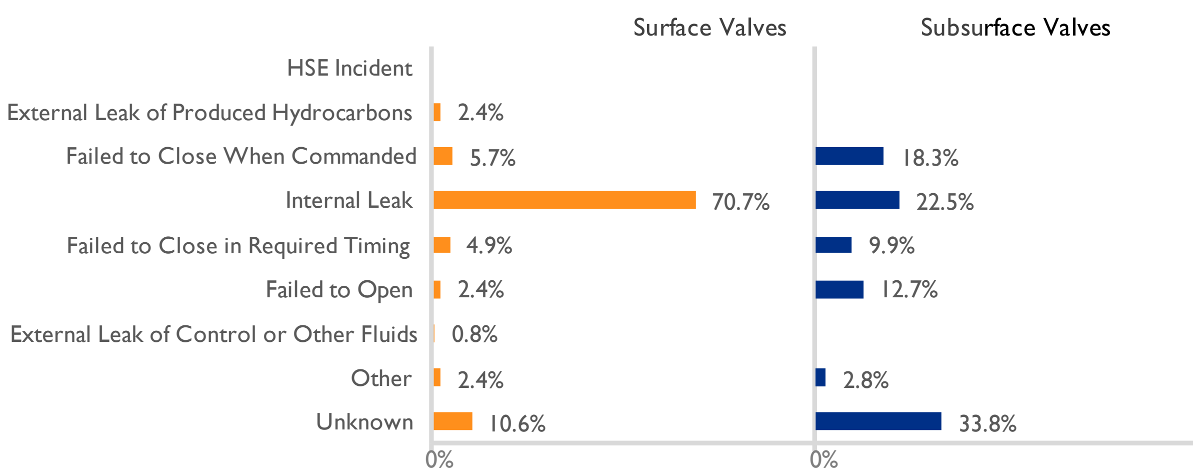
SSV	2	Broken spring in actuator found after failure to close, one for testing and one during normal operation	Repair – replaced spring
	2	Failed to close for ESD testing, one due to atmospheric corrosion and one due to elastomeric degradation	Repair
	1	Actuator packing failure found during normal operations	Repair – replaced packing
	1	Failed when operator closed during normal operations	Repair

NOTE: Events in **bold** print were on higher rate wells (>1000 bopd or mcfd) and are described further in the *Failure Types by Well Rate Section* of this report. Events with unknown corrective action were identified in INC data.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

In addition, BTS reviewed a 2023 BSEE incident investigation of a suspected well tubing failure that may have caused the release of 16 barrels of hydraulic fluid and completion fluids during commissioning of a subsea well. An SCSSV and its control lines were discussed in the incident summary, but the event was not classified as an SPPE failure based on the uncertainty of the details of the failure. In the future, after the well undergoes a workover to recover the tubing and determine what failed, this event may be classified as an SPPE failure.

Figure 9 illustrates the event types for surface valves and subsurface valves described above. Events with unknown event type were identified in other sources (APM, OGOR-A, or WAR data) and did not provide enough information to determine the event type.

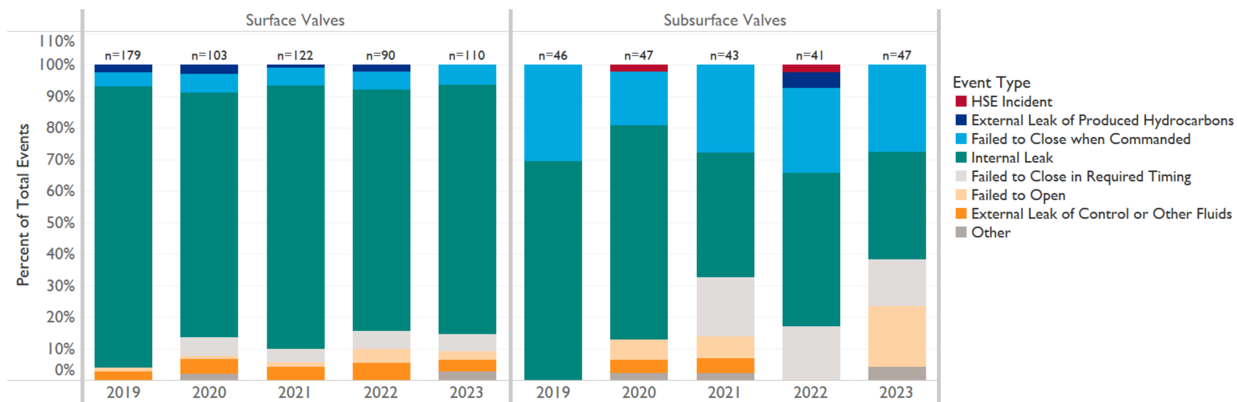
Figure 9: Event Types in Order of Significance, 2023



NOTE: Percentages are of 123 surface valve failures and 71 subsurface valve failures, respectively. Only the most significant event type is shown for the few failures with multiple reported types. Events with unknown event type were identified in other sources (APM, OGOR-A, or WAR data) and did not provide enough information to determine the event type.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Figure 10 shows the distribution of event types each year since 2017. Internal leak is the predominant failure mode for surface valves, comprising greater than three-quarters of event types annually. For subsurface valves, the most frequent failure modes are internal leak and failure to close. For subsurface valves, failure to close and failure to open were more prominent in 2023 (29 of 47 events) than in past years, although the total number of subsurface valve failures with known event type has remained relatively consistent.

Figure 10: Failure Events by Type, 2017-2023



NOTE: Percentage is of the number of events, where only the most significant event type is shown for the few failures with multiple reported types. One HSE event is shown for 2020 and 2022, respectively, identified in BSEE incident data. Both events involved SCSSV piston seal failures resulting in releases of produced fluids to the environment.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Well Location and Status

Shallow Water Province versus Deepwater

As shown in Table 4, most active wells in 2023 (75.7 percent) were within the shallow water province, which BSEE defines as water depths of under 200 meters (656 feet).[21] Most SPPE failures (73.8 percent) were also associated with shallow water wells. Therefore, to facilitate comparison across water depth groups, the proportion of SPPE failures for each group was evaluated against an expected proportion of failures equal to one (indicating an expected equal likelihood of failure across groups). The actual to expected failure ratio is calculated by dividing the percentage of SPPE failures by the percentage of active wells in each group. A number higher than one indicates a greater proportion of failures than expected. Similar to previous years, in 2023 wells in the 200 to 800-meter water depth range had a higher actual to expected failure ratio compared to wells in the other water depth groups. Notably, two of the repeated failures (discussed further under *Repeated Failures*) were on wells in this water depth and contributed to the failure ratio.

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

Table 4: Distribution of SPPE Failures by Water Depth, 2023

Water Depth (m)	SPPE Failures	Active Wells	Actual to Expected Failure Ratio
< 200 (656 ft)	138 (73.8%)	3,220 (75.7%)	0.97
200 - 800	20 (10.7%)	309 (7.3%)	1.47
> 800 (2,625 ft)	29 (15.5%)	725 (17.0%)	0.91
Total	*187*	*4,254*	*N/A*

NOTE: Total excludes seven failures for which water depth was not reported or multiple wells were associated with the failure. Actual to expected failure ratio = pct. of SPPE failures / pct. of active wells.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

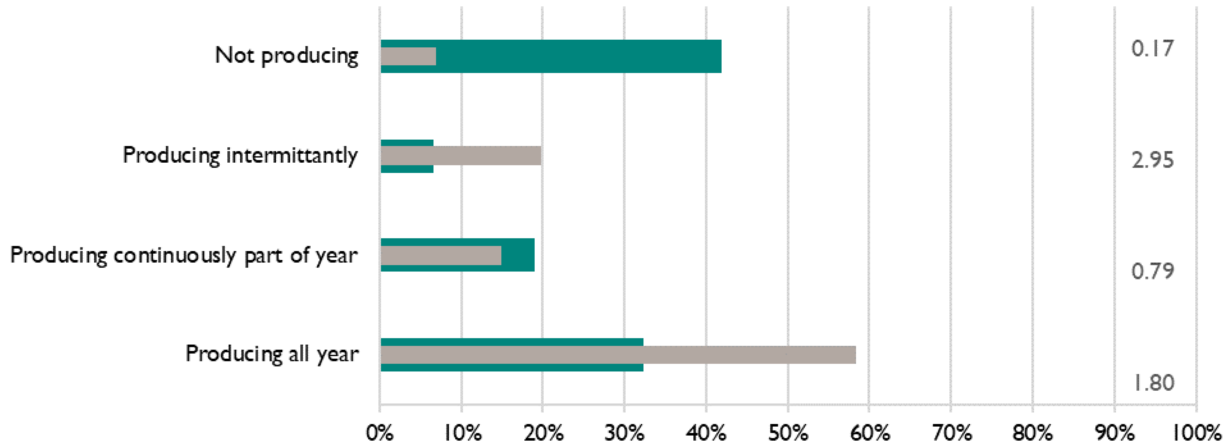
Well Status and Production Time

To examine potential relationships between well status and occurrence of SPPE failure, wells were categorized based on their annual average production rates as well as the amount of time over the course of the year the well was in producing status (see Appendix D for more details). These categories include:

- *Producing all year* – the well produced at least one day in all 12 months of 2023.
- *Producing continuously part of the year* – the well produced between one and 11 months, and for the months that there was production, it produced on at least half of the days in the month.
- *Producing intermittently* – the well produced at least one day in at least one but not more than 11 months, and it produced less than half of the days in the months that it produced.
- *Non-producing* – the well did not produce a single day in 2023.

Figure 11 compares the production time grouping of the population of active wells to the production time grouping of the wells with SPPE failures. The actual to expected failure ratio, shown on the right side of the chart, is calculated by dividing the percentage of SPPE failures (surface and subsurface valve failures combined) by the percentage of active wells in each group. A number higher than one indicates a greater proportion of failures than expected. As in 2022, the 2023 "producing intermittently" and "producing all year" groups show the highest percentages of failures (19.8 and 58.3 percent, respectively) and the highest failure ratios (2.95 and 1.80, respectively). Most (93.0 percent) failures occurred on wells that produced at least one day in 2023.

Figure 11: Status for All Wells vs. Wells with SPPE Failure, 2023



	Producing all year	Producing continuously part of year	Producing intermittantly	Not producing
% of Production Well Population	32.3%	19.0%	6.7%	42.0%
% of Failures	58.3%	15.0%	19.8%	7.0%

NOTES:

1. Active wells: n=4,179, which excludes water source and water injection wells.
2. Wells with SPPE failure: n=187. Status is based on the days producing during the 12 months prior to the month of the failure. Excludes four failures of GLSDVs and three failures of a BSDV, which can serve multiple wells producing into a common subsea flowline.
3. Actual to expected failure ratio (at right) = percent of SPPE failures / percent of active wells.

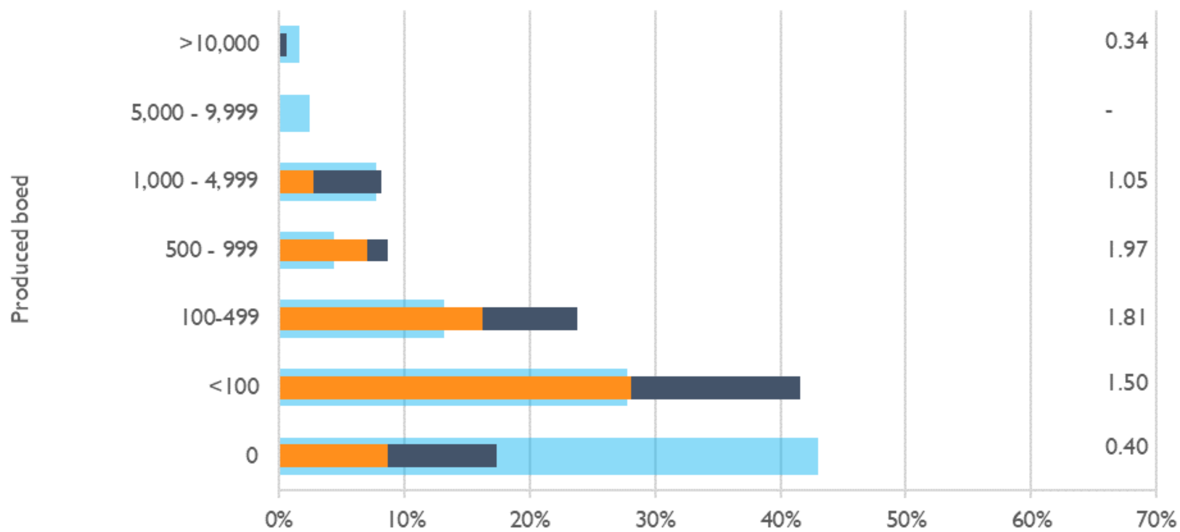
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Well Fluid Rates

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

Figure 12 compares the SPPE failures grouped by well rate range with the well rates of active wells in the GOM OCS during the month prior to the failure. The actual to expected failure ratio, shown on the right side of the chart, is calculated by dividing the percentage of SPPE failures (surface and subsurface valve failures combined) by the percentage of active wells in each group. A number higher than one indicates a greater proportion of failures than expected. In 2023, most failures (82.7 percent) were associated with wells that produced less than 500 boed, with 58.9 percent producing less than 100 boed. These figures represent decreases from 87.6 percent and 59.7 percent, respectively, in 2022. These wells pose a lower risk than higher-producing wells. About 0.5 percent of the reported failures (on single wells where the well number was identified) were associated with wells producing more than 5,000 boed.

Figure 12: Well Rates for All Wells vs. Wells with SPPE Failure, 2023



	0	<100	100-499	500 - 999	1,000 - 4,999	5,000 - 9,999	>10,000
Well Population	43.0%	27.8%	13.2%	4.4%	7.7%	2.4%	1.6%
Surface Valve Failures	8.6%	28.1%	16.2%	7.0%	2.7%	0.0%	0.0%
Subsurface Valve Failures	8.6%	13.5%	7.6%	1.6%	5.4%	0.0%	0.5%

NOTES:
1. Active wells: n=4,254. Rate is the Jan. – Dec. 2023 average.
2. Wells with SPPE failure: n=185. Rate is taken from near the time of the failure. Excludes nine failures where there was no production reported or it involves a GLSDV or BSDV with multiple wells.
3. Actual to expected failure ratio (at right) = percent of SPPE failures (surface + subsurface) / percent of active wells.

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

The average daily production rates shown in the figures above can offer insight into the potential environmental exposure of the failures. The total daily production volume from the wells that experienced a reported SPPE failure in 2023 was 44,337 boed. Comparing this figure to the average daily production from the GOM OCS in 2023 (2.79 million boed) indicates that 1.6 percent of the GOM OCS production could have been directly affected by the 95 reported SPPE failures, compared to 2.5 percent in 2022. Considering failures identified in all data sources (SafeOCS, APM, INC, OGOR-A, WAR, and BSEE incident data), the average daily production volume from wells with an SPPE failure in 2023 increases to 72,100 boed, representing 2.6 percent[22] of GOM OCS production, also less than the

[22] This percentage could be underestimated due to a small number of failures lacking production information.

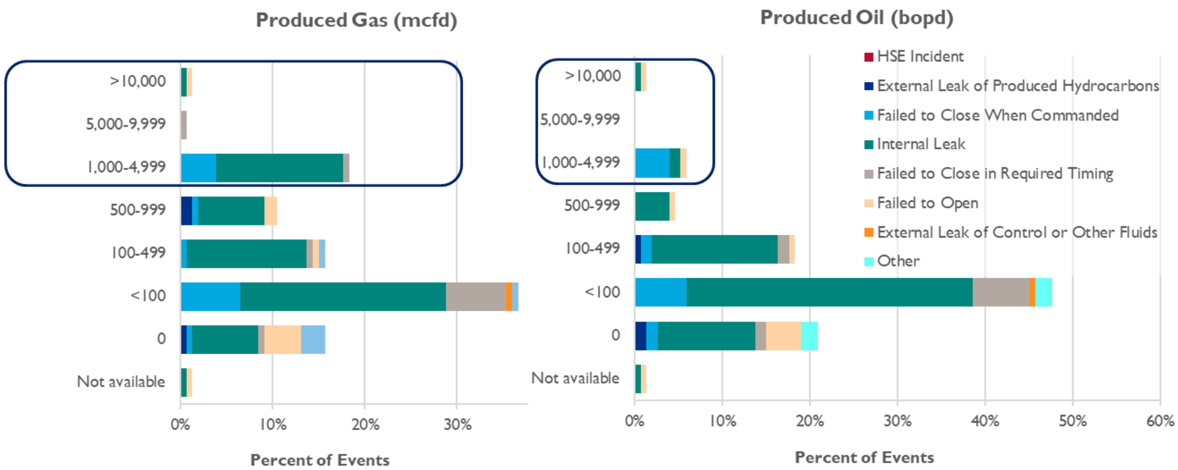
3.4 percent in 2022.

Failure Types by Well Rate

Along with the nature of the failure, the well's production rate is important in evaluating the potential environmental impact. Figure 13 shows the distribution of failures by well rate, with failure type indicated by color. In 2023, there were no reported HSE events, and there were no external leaks of hydrocarbons on wells in the higher well rate ranges (>1000 bopd or mcfd). There were, however, six failures on higher producing wells where the valves failed to close when commanded. These failures are described below:

- Three of the five single well failures occurred the same day during an ESD caused by sand-blasting dust triggering two smoke detectors, which then triggered the ESD. After investigation, the cause of the three SCSSVs failing to close was determined to be a flaw in the programming logic affecting these wells. The corrective action was to address the ESD programming issue.
- One of the five SCSSVs failures occurred on a well with known contaminants, such as scale and asphaltenes, despite continues asphaltene inhibitor injection. After many attempts with xylene and acid treatments with a coil tubing unit, the chemical treatment was successful in restoring the valve performance.
- One of the five SCSSVs failed to close due to organic deposition around the flow tube during flowback following an acid stimulation on a subsea well with an HPHT SCSSV. Operations was able to change the flowing conditions of the well to restore proper operation of the valve.
- The sixth event involved a nine-year-old BSDV that failed to close for the monthly leakage test due corrosion in the actuator stem bore below the stem protector. The valve was repaired with an improved design stem protector.

Figure 13: Type of Reported Failures by Well Rate, 2023

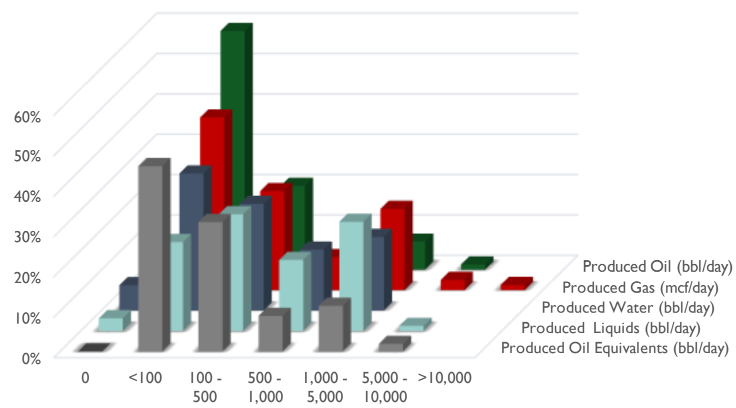


NOTE: Percentage is of the number of events with known failure type (n=157), where only the most significant event type is shown for the few failures with multiple reported types. Events of unknown type are excluded. The well rates were summed for failures of BSDVs that serve multiple wells.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Rates of Oil, Gas, and Water

Some failures may have been related to the produced fluid stream passing through the valve. For most analyses presented in this section, failures not related to the fluids in the well are excluded (for example, an external leak of control fluid). For failures possibly affected by produced well fluids (fluid-affected failures), different parameters related to the oil, gas, and water phases of the produced fluid stream were evaluated. Figure 14 shows the distribution of 2023 potentially fluid-affected failures independently for several production rate parameters, based on the annual average of the production from the well over the 12 months prior to the failure. For produced oil, most failures (79.9 percent) were on wells producing greater than zero and less than 500 bopd. The

Figure 14: Failures Grouped by Well Fluid Rate Ranges, 2023

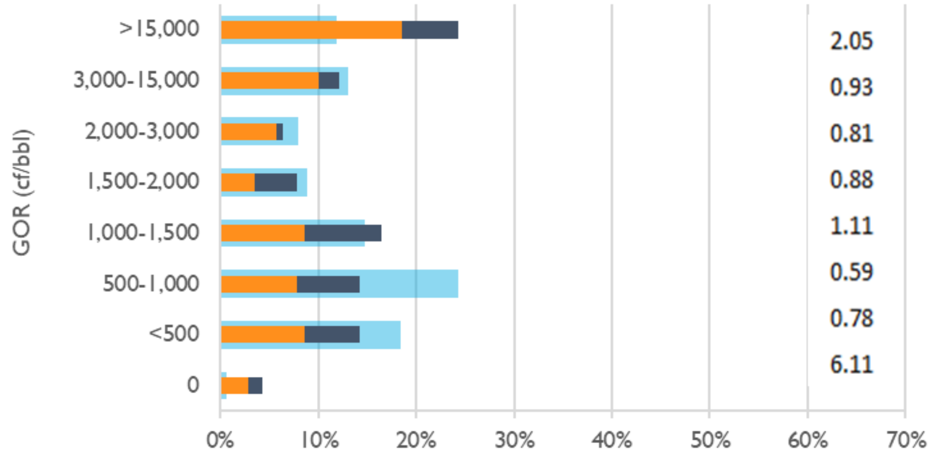


NOTE: Includes 159 total failures where produced fluids could have been a factor in the failure and well rates were available.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

breakdown is similar for produced gas and water and the two calculated parameters (produced oil equivalents and produced liquids).

The fluid proportions produced from each well differ depending on the reservoir and placement of the well in that reservoir. The gas-oil ratio (GOR) describes the volume of gas produced from the well as compared to the volume of oil produced, and it can be useful in determining whether a well primarily produces gas or oil. Figure 15 shows the breakdown of producing wells into GOR ranges. The actual to expected failure ratio, shown on the right side of the chart, is calculated by dividing the percentage of SPPE failures (surface and subsurface valve failures combined) by the percentage of active wells in each group. A number higher than one indicates a greater proportion of failures than expected based on the percentage of wells in that category. As seen in the figure, the failure ratio for wells in the highest GOR group and lowest GOR group had higher failure ratios, indicating disproportionately more failures on these wells compared to wells in other GOR groups. Higher gas production rates for these wells means higher velocities toward the top of the well, potentially leading to more failures from correspondingly more erosive solids in the flow stream. The other group with a very high failure ratio is the zero GOR group. This consists of wells that produced some oil, but no gas. There are only 17 wells with this characteristic, and six failures occurred on five of them in 2023. Four were SSVs and two were subsurface safety valves. Three of the six failures were leaks, either external or internal, and the event type of the other three could not be determined from the available information. Most of these failures were identified in other sources (e.g., BSEE WAR data).

Figure 15: SPPE Failures and Producing Wells by GOR Range, 2023



	0	<500	500-1,000	1,000-1,500	1,500-2,000	2,000-3,000	3,000-15,000	>15,000
Well Population	0.7%	18.4%	24.2%	14.8%	8.9%	8.0%	13.1%	11.8%
Surface Valve Failures	2.9%	8.6%	7.9%	8.6%	3.6%	5.7%	10.0%	18.6%
Subsurface Valve Failures	1.4%	5.7%	6.4%	7.9%	4.3%	0.7%	2.1%	5.7%

NOTES:
1. Active wells: n=2,425. Includes producing wells only.
2. Wells with SPPE failure: n=140. Includes failures on producing wells where produced fluids could have been a factor in the failure and the well produced in the month prior to the failure.
3. Actual to expected failure ratio = percent of SPPE failures (surface + subsurface) / percent of active wells.

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

SPPE Pressure Rating

Between 2017 to 2023, 135 SPPE failure events, including 11 in 2022 and 15 in 2023, involved a valve designed for high pressure or high temperature (HPHT) conditions (i.e., having a design or working pressure of at least 15,000 psi or a temperature rating of at least 350°F).[23,24] The 15 events occurring in 2023 involved eight surface valves and seven subsea wells. Three of the failures involving subsurface valves that failed to close (two SSCSVs and one SCSSV) and another event involving an external leak of an HPHT SSV are described in the *Failures and Potential Consequences* section above. Seven of the failures of HPHT valves involved internal leakage (six SSVs and one BSDV). The remaining four were SCSSV failures to open reporting a design issue. None of the 2023 events reported operating a valve in conditions out of its specified pressure or temperature range as a contributing factor to the failure.

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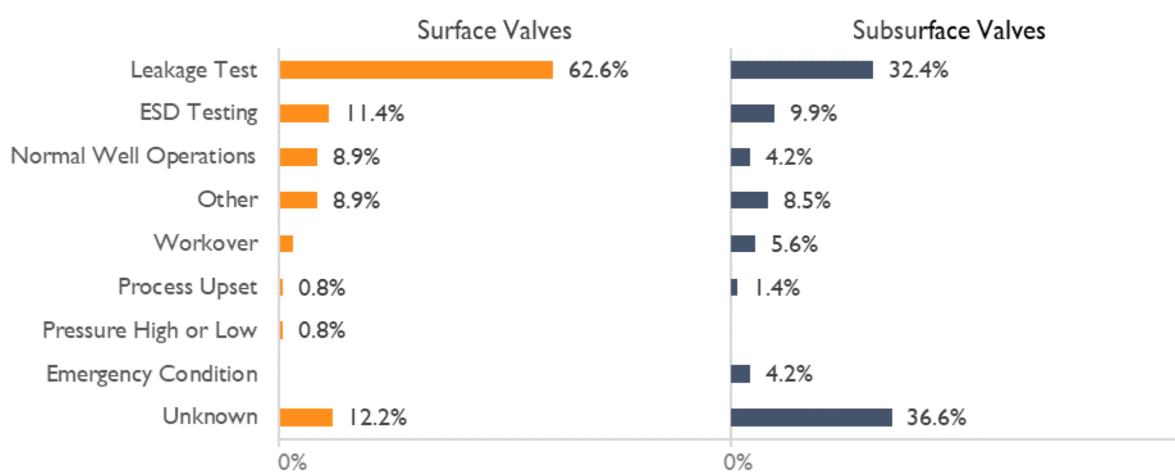
[23] BSEE regulations define HPHT environment as when the maximum anticipated surface pressure or shut-in tubing pressure is >15,000 psia or the flowing temperature is ≥350 F (see 30 CFR 250.804(b)). For purposes of this report, valves rated at exactly 15,000 psi (rather than strictly greater than 15,000) were considered designed for HPHT conditions.

[24] For this annual report, BTS performed a quality review of reported failure events to compare the reported pressure rating to the HPHT checkbox on the form, and updated the checkbox to match the rating where appropriate.

When Failures Were Detected

SPPE failures can occur when the valve is automatically or manually commanded to close via the control system. They can be detected at various times, such as during testing, while the equipment is in normal operation, or when production halts (is shut-in) due to abnormal or emergency conditions. For 2023, most failures (62.6 percent of surface valves and 32.4 percent of subsurface valves) were found during routine leakage tests (see Figure 16). These failures found during leak testing included four that also listed normal operations and three that also listed ESD testing, which was the second highest detection method besides "other." Seventeen additional failure reports indicated "other" for the detection method, including seven found during BSEE inspections, four related to start-up or shut-down activities, two when pulled for inspection, one while performing casing diagnostics, and three found during normal operations.

Figure 16: Failure Detection Methods, 2023



NOTE: Percentages are of 123 surface valve failures and 71 subsurface valve failures, respectively. Totals exceed 100 percent because more than one detection method may be reported for a single event.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

How Failures Were Addressed

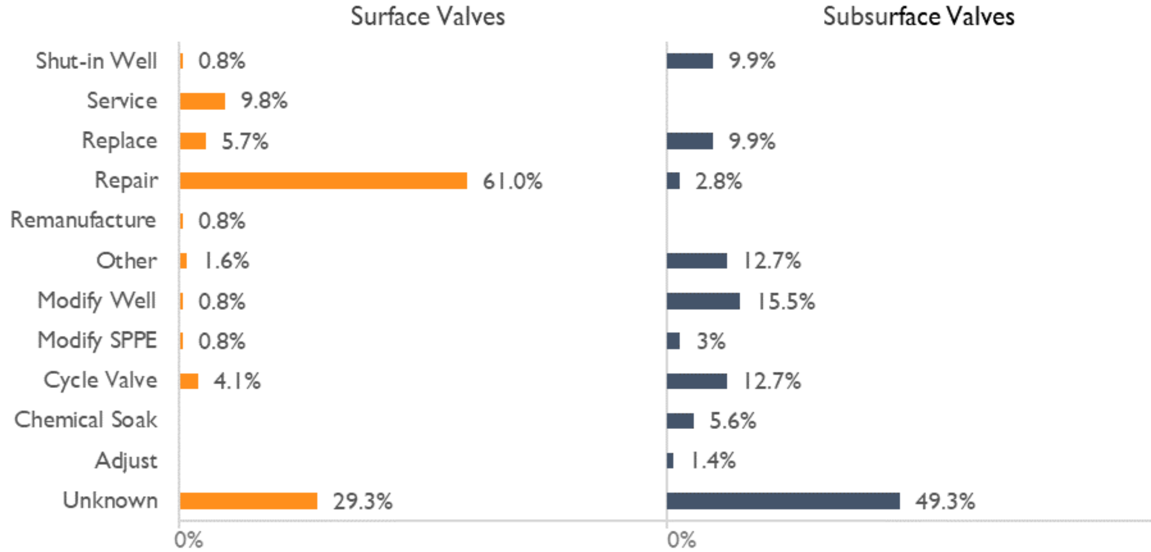
In 2023, corrective actions were identified for 123 failures (63.4 percent), including 95 reported to SafeOCS and 28 identified in other sources. Figure 17 shows the distribution of corrective actions, which range from component servicing to repair or replacement. For surface valves, repair was the most common corrective action, reported for over half (61.0 percent) of events. For nearly three quarters (74.3 percent) of surface valve failures involving repair, the repaired component was the valve gate or seat. The next largest group (16.2 percent) of repaired surface valves were corrected by repairing or replacing the actuator.

For 27 failures, multiple corrective actions were taken to address the issue, including 13 cases of repairing and either cycling the valve, servicing the valve, or both. Ten other cases of cycling the valve with another action such as chemical soaking the valve, servicing the valve, or shutting in the well. Brief explanations of the corrective actions are provided below:

- *Shut-in Well* – the well was shut-in for at least 30 days, meaning valves were closed to halt flow from the well, either permanently or until remediation can be performed.
- *Modify Well* – a change was made to the well barrier configuration (e.g., setting a tubing plug).
- *Modify SPPE* – a change was made to the valve (e.g., replacing it with a different model or type).
- *Replace SPPE* – the entire valve was replaced with the same valve type.
- *Remanufacture* – the valve was rebuilt by the manufacturer using restored, repaired, or new parts.
- *Chemical Soak* – a chemical solvent was introduced to the valve to dissolve buildups of contaminants such as scale or asphaltenes.
- *Repair* – the valve was repaired, or part of the valve (i.e., a component) was replaced.
- *Service* – maintenance was performed on the valve (e.g., greasing).
- *Adjust* – maintenance was performed that involved fine-tuning the valve or operational settings (e.g., control system settings).
- *Cycle Valve* – the valve was stroked, meaning it was moved from its fully open position to its fully closed position and back to fully open.

Nine of the subsurface valve failures reported "other" corrective action, such as ESD logic updates, altering flowing conditions to reduce contaminant effects, ordering a replacement valve, or cleaning the SCSSV using a wireline scratcher. The high percentages shown for "unknown" corrective action are mainly due to the failures that are not reported to SafeOCS, but are found in other information databases (INC, OGOR-A, APM, WAR, and BSEE incident data). These sources rarely mention the corrective action.

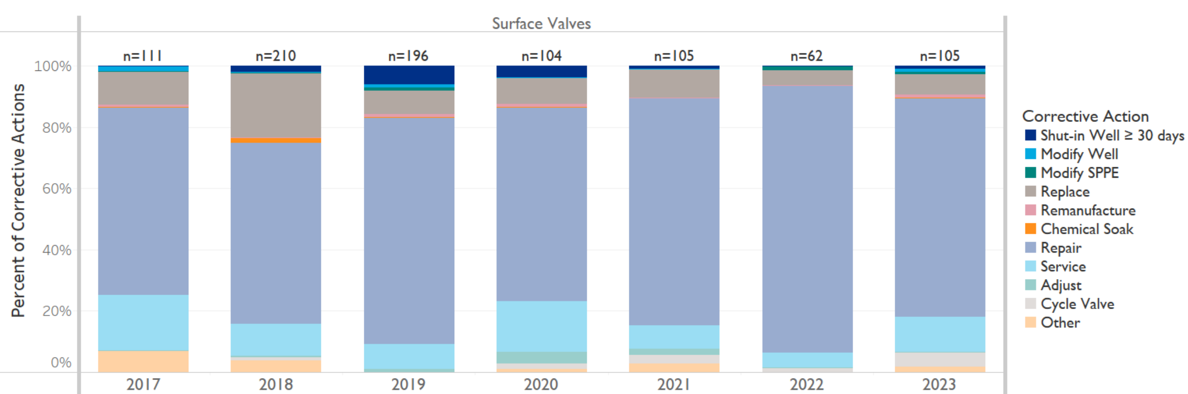
Figure 17: Reported Corrective Actions, 2023



NOTE: Percentages are of 123 surface valve failures and 71 subsurface valve failures, respectively. Totals exceed 100 percent because more than one corrective action may be reported for a single event.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

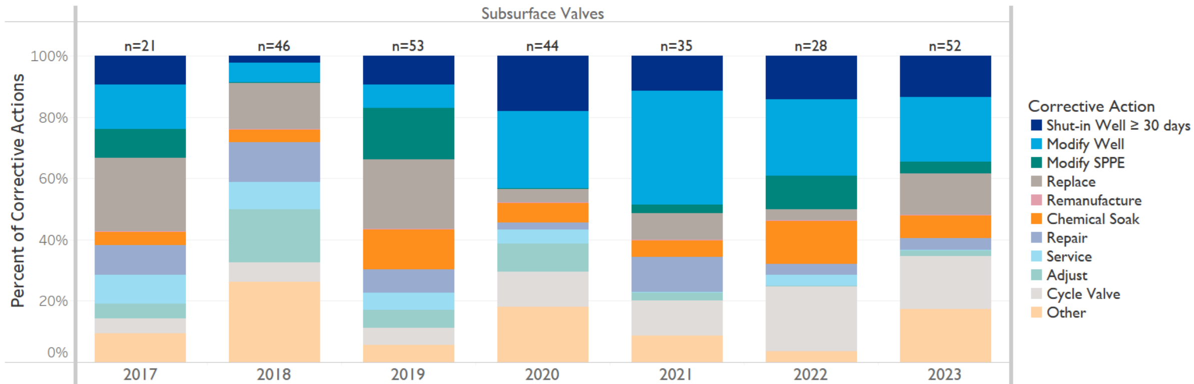
Figure 18 and Figure 19 show the distribution of corrective actions each year since 2017 for surface and subsurface vales. While most surface valves were corrected by repair (i.e., replacing the gates and seats or repairing/replacing the actuator), corrective actions were more varied for subsurface valves. The more common corrective actions for subsurface valves since 2019 include well shut-in, well modification, and cycling the valve. The "other" corrective actions for subsurface valves mostly involve cases where the subsurface valve was cleaned using a wireline scratching tool.

Figure 18: Reported Corrective Actions, 2017-2023 (Surface Valves)



NOTE: Percentage is of the number of corrective actions identified in SPPE failures. Corrective actions were not reported for all failures, and more than one corrective action can apply to a single failure.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Figure 19: Reported Corrective Actions, 2017-2023 (Subsurface Valves)



NOTE: Percentage is of the number of corrective actions identified in SPPE failures. Corrective actions were not reported for all failures, and more than one corrective action can apply to a single failure.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Root Causes and Contributing Factors of Failures

Root Causes

Root cause failure analysis (RCFA) consists of various investigative methods used to determine failure causes and contributing factors. Often the process involves identifying preventive actions to reduce or eliminate the likelihood of reoccurrence. Twelve failure reports in 2023 included information about preventive actions planned or taken, summarized in Table 5.

Table 5: Overview of 2023 Preventive Actions

SPPE Type	Component	Failure Type	Root Cause	Preventive Action(s)
SCSSV (3 valves)	ESD System	Failed to close	Unknown	Updated logic for ESD system.
SCSSV (2 valves)	Hydraulic control system	Failed to open	Design issue	Replaced SPPE with different type.
SCSSV	Flapper	Internal leak	Design issue	Will modify well to install a pump through plug.
GLSDV (2 valves)	Valve Gate/Seat	Internal leak	Maintenance plan and procedure	Emphasized greasing frequency. Also installed a new vent on the actuator to prevent water from entering the actuator housing.
GLSDV	Valve Gate/Seat	Internal leak	Design issue	Material change on valve seat and new inner seal.
BSDV	Other	External leak	Maintenance plan and procedure	Routine valve greasing.
BSDV	Valve Gate/Seat	Internal leak	Wear and tear	Routine valve greasing; Use Peek or metal seated valves.
BSDV	Actuator	Failed to close	Wear and tear	Utilize a new style stem protector that is one piece stainless with a pressed in seal.

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

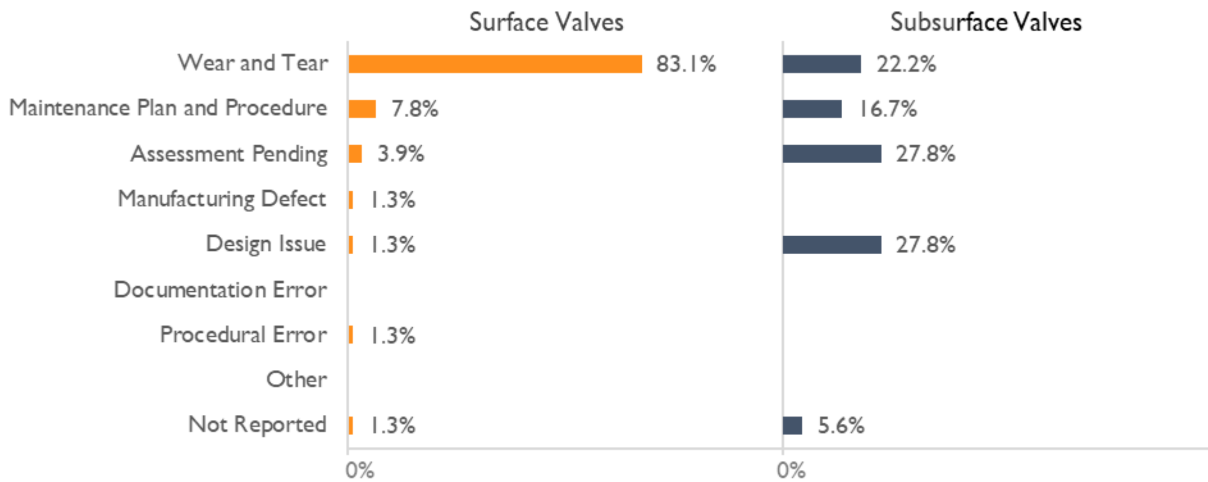
Figure 20 shows the reported root causes of SPPE failures reported to SafeOCS for 2023. Wear and tear, which SafeOCS defines as "an expected condition of a component that has reached a point where it is unable to perform its intended function as the result of usage or it has met its expected life," was the most common reported cause of surface valve failures, reported for 83.1 percent of the 77 events.

Fifteen of the 77 surface valves were SSVs that failed within 12 months of installation or a qualifying repair yet listed wear and tear as the root cause. Nine of the SSV failures were determined to be repeated failures, which are discussed in the *Repeated Failures* section below. The six remaining failures within 12 months where *wear and tear* was the reported root cause may warrant additional review by the equipment owner or operator. One was reported as an SSV failure to close due to an actuator spring failure where atmospheric corrosion was a contributing factor. One of the six SSVs failed to close and listed "improper maintenance or repair" and "assembly damage or error" with a root cause of wear and tear. In that case, scale was noted as an environmental condition, but not marked as a contributing factor. The remaining four premature failures were internal leaks, one of which mentioned internal chemical corrosion in the valve body and three listed the gates and seats as the failed component. Like the repeated failures, these four SSV premature failures were on wells with over 75 percent watercut, and three of the four reported scale as an environmental condition.

Of 18 subsurface valve failures reported to SafeOCS in 2023, the most common reported cause was design issue, reported for five events after receiving no reported design issues in 2022. These design issues included four SCSSVs failing to open on subsea wells and one SCSSV with an internal leak. The design issue was related to lack of tolerance for asphaltenes in two of the SCSSV failures to open, and the SCSSVs were ultimately replaced. In addition to the subsurface valves with design issues, five subsurface failure events were still being investigated at the time of reporting (i.e., "assessment pending"), and no updated information has been provided to SafeOCS. BTS is engaging with stakeholders to improve the capability of SafeOCS to receive more frequent updates to reported events as they are investigated.

Maintenance plan and procedure was determined to be the root cause of nine events, including six surface valves and three subsurface valves. Among these nine cases were a BSDV external leak from the actuator, two GLSDV internal leaks where grit was found in the lubricating grease, one SSV failure to close due to atmospheric corrosion in the actuator, internal leaks of two SSV and one SCSSV that mention scale and other contaminants, and two SCSSVs that failed to close due to paraffin and/or asphaltene deposition in the valve.

Figure 20: Root Causes of Reported Failure Events, 2023

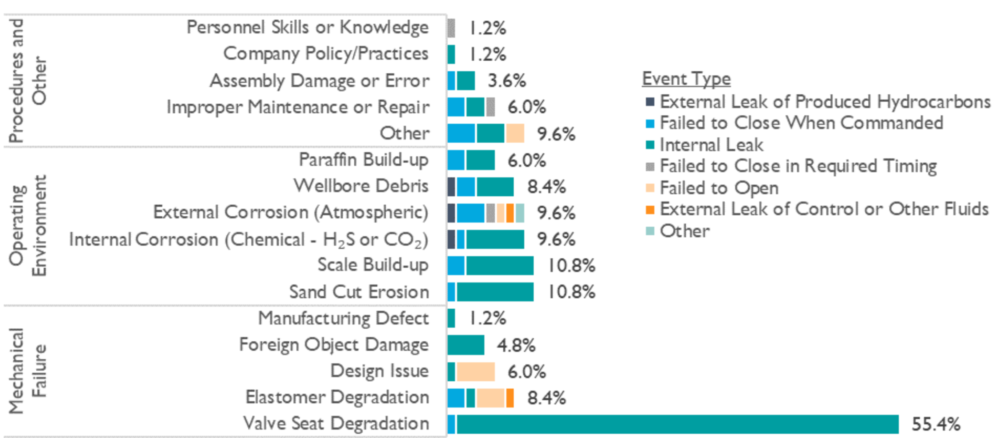


NOTE: Percentages are of 77 surface valve failures and 18 subsurface valve failures reported to SafeOCS, respectively.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Contributing Factors

Operators are asked to report all contributing factors associated with a failure. These factors can relate to procedures and practices, operating environment, mechanical failure, human error, and other areas. Information on contributing factors was available for 83 failures occurring in 2023, including 81 failures reported to SafeOCS and two identified in APM and WAR. In total, 127 contributing factors were reported for the 83 failures (more than one contributing factor may be reported for a single failure). The distribution of contributing factors for these failures is shown in Figure 21.

Figure 21: Factors Contributing to Equipment Failures, 2023



NOTE: Percentage is of 83 failures where contributing factors were known to BTS. Total exceeds 100 percent because more than one contributing factor may be reported for a single event.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

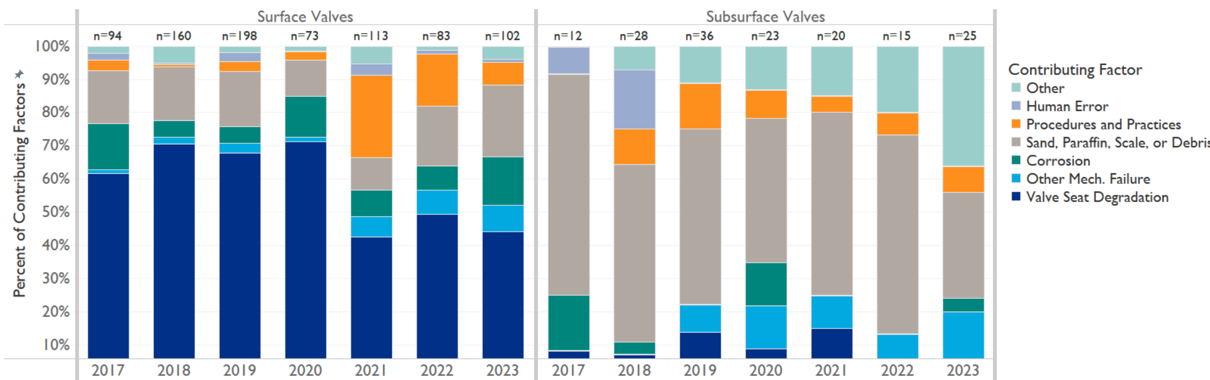
Valve seat degradation was the most reported contributing factor, reported for 55.4 percent of the 83 events, compared to 65.1 percent reported in 2022. When combined, contributing factors related to the operating environment—atmospheric or chemical corrosion, sand, paraffin, debris, and scale—were also reported for the same percentage of events as valve seat degradation at 55.4 percent, up from 47.6 in 2022 and 40.2 percent in 2021. Among these, chemical corrosion (internal corrosion usually caused by the presence of either H_2S or CO_2) or atmospheric corrosion (external corrosion usually caused by moisture or chlorides that affect susceptible metal surfaces) were each listed as a contributing factor for 9.6 percent of the failures, both double compared to the portion in 2022. Depending on the metallurgy, the temperature, and the concentration of H_2S or CO_2, corrosion could occur quickly or from prolonged exposure. Of the eight events with chemical corrosion as a contributing factor, two were repeated failures (the GLSDV and an SSV), discussed below under *Repeated Failures*. However, the other six cases involving chemical corrosion were on wells with either higher watercut (>40 percent) or high GOR (>15,000), or both high watercut and high GOR. In addition, all six reported at least one contaminant in the flow stream. Sand, scale, and paraffin also increased in occurrence while wellbore debris contributed to fewer events in 2023. The eight events (9.6 percent) where "other" contributing factors were reported included descriptions of asphaltenes (a solid contaminant) in five SCSSVs, a raised and missing seal in an SSV, and the presence of grit in the lubricating grease on two GLSDVs.

For 26 failures, two or more contributing factors were reported. In 13 of these cases, *valve seat degradation* was reported with an operating environment factor of sand cut erosion, scale, paraffin, well debris, or chemical corrosion. Of these 13, two also listed elastomeric degradation, one also listed *improper maintenance or repair*, two were listed with *assembly damage or error* (one of which also listed foreign object damage), one listed a *manufacturing defect*, and one noted a *design issue*. Eleven additional failures were reported with contributing factors related to the operating environment, such as sand, wellbore debris, asphaltenes, paraffin, scale, and/or foreign objects.

In the "Procedures and Other" group, two SSV failures involved more than one contributing factor. In one case where the SSV failed to close, "improper maintenance" and "assembly damage or error" were reported without further explanation. Both "personnel skills" or "knowledge and atmospheric corrosion" were reported with "improper maintenance" in the other case where light corrosion on the "dry" stem prevented the SSV from closing in the required timing.

Figure 22 shows the distribution of contributing factors each year since 2017. Valve seat degradation was reported more frequently for surface valves, while solid contaminants (sand, paraffin, scale, or debris) were reported more frequently for subsurface valves. The "other" contributing factors, which increased every year since 2018 as a percentage of the failures, include two design issues that also mention asphaltenes and three additional cases of asphaltenes in the subsurface valves in 2023. BTS will consider adding asphaltenes as a separate contributing factor to the form.

Figure 22: Factors Contributing to Equipment Failures, 2017-2023



NOTES: Percentage is of the number of contributing factors identified in SPPE failures. Contributing factors were not reported for all failures, and more than one can apply to a single failure.

- Other consists of design issue, operating conditions out of range of device, and other failure factors.
- Human Error consists of personnel skills or knowledge, quality of task execution, and quality of task planning and preparation.
- Procedures and Practices consists of assembly damage or error, improper maintenance or repair, improper use or valve alignment, company policy/practices, and workplace documentation.
- Sand, Paraffin, Scale, or Debris consists of paraffin build-up, sand cut erosion, scale build-up, and wellbore debris.
- Corrosion consists of external (atmosphere) and internal (chemical – H_2S or CO_2).
- Other Mechanical Failure consists of manufacturing defect, elastomer degradation, hydraulic power failure, and foreign object damage.

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

Contaminants and Valve Class

In addition to oil, gas, and water, produced fluids may contain unfavorable contaminants, such as sand, hydrogen sulfide (H_2S), or carbon dioxide (CO_2). Although the presence of well stream contaminants is not always related to a failure, it can be a contributing factor. Well fluids can carry solids such as sand through the tree's valves during production, which can cause mechanical damage by eroding the equipment and plugging components within the production equipment. Some wells naturally contain H_2S or CO_2, both of which can lead to corrosion damage to the equipment if not properly mitigated.

The analysis of contaminants presented in this section includes only failures reported to SafeOCS because failures identified in other sources (APM, INC, OGOR-A, WAR, or BSE incident data) included little to no information on contaminants. A greater percentage of these failures (48.4 percent) reported contaminants in 2023, increasing from 39.1 percent in 2022 and 27.2 percent in 2021. These are shown in Figure 23 along with the service class of the failed valves. The service class corresponds to the operating conditions for which a valve is designed.

SSVs, BSDVs, and USVs have the following 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.

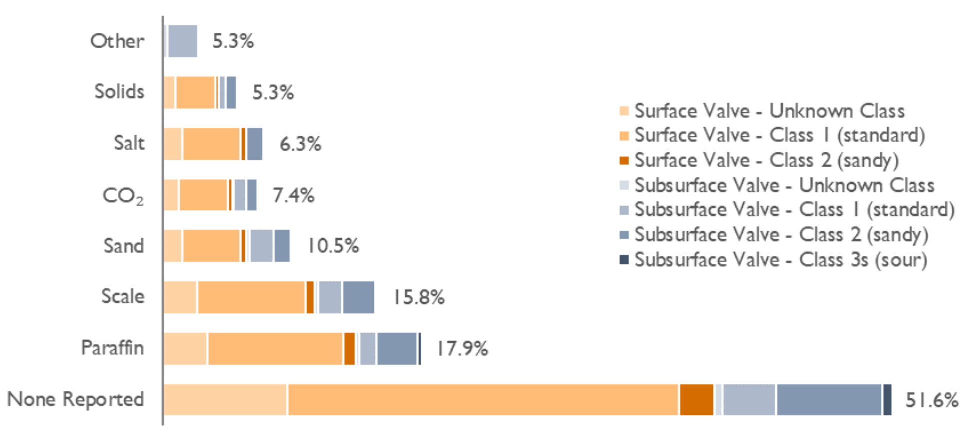
Six SSV failures indicated the presence of sand; one of these involved a Class 2 valve, and five were Class 1 valves. Thirty-five (35) SSV failures indicated the presence of other solids (paraffin, scale, salt, cement, or other solids) in the well stream, and eleven of these involved Class 2 valves. Of the 77 surface SPPE failures reported to SafeOCS in 2023, 48 (62.3 percent) were Class 1, 15 (19.5 percent) were Class 2, and the remainder did not report the service class.

Subsurface safety valves (SCSSVs and SSCSVs) have the following service classes:

- 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.

Four of the SCSSV failures indicated the presence of sand. Of 16 SCSSV failures reported to SafeOCS in 2023, 11 indicated the presence of other solids (paraffin, asphaltenes, salt, solids, or scale) in the well stream. three of these were reported as a Class 1 and 2 valves, and eight were Class 1 valves.

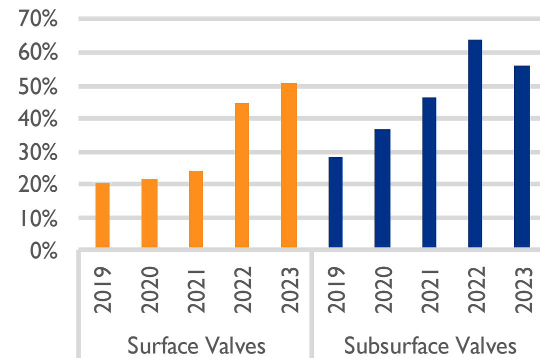
Figure 23: Well Stream Contaminants, 2023



NOTE: Percentage is of 95 failures reported to SafeOCS. Total sums to greater than 100 percent because reporters could choose more than one contaminant.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

As shown in Figure 24, the percent of failures with reported solid contaminants steadily increased from 2019 to 2023 for surface valves and from 2019 to 2022 for subsurface valves, decreasing slightly in 2023. These trends could indicate contaminants are increasingly present in wells with SPPE failures, but the increase also could be driven by improved reporting of contaminants following the data collection form revision in 2020. It is uncertain whether this trend indicates improved reporting of contaminants or an actual increase in contaminants present in wells with failed SPPE valves. In 2023, the increase in contaminants is also reflected in the contributing factors data presented above (see Figure 21).

Figure 24: Well Stream Solid Contaminants, 2019-2023



NOTE: Percentage is of failures reported to SafeOCS each year. Excludes failures identified in other sources.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Time to Failure

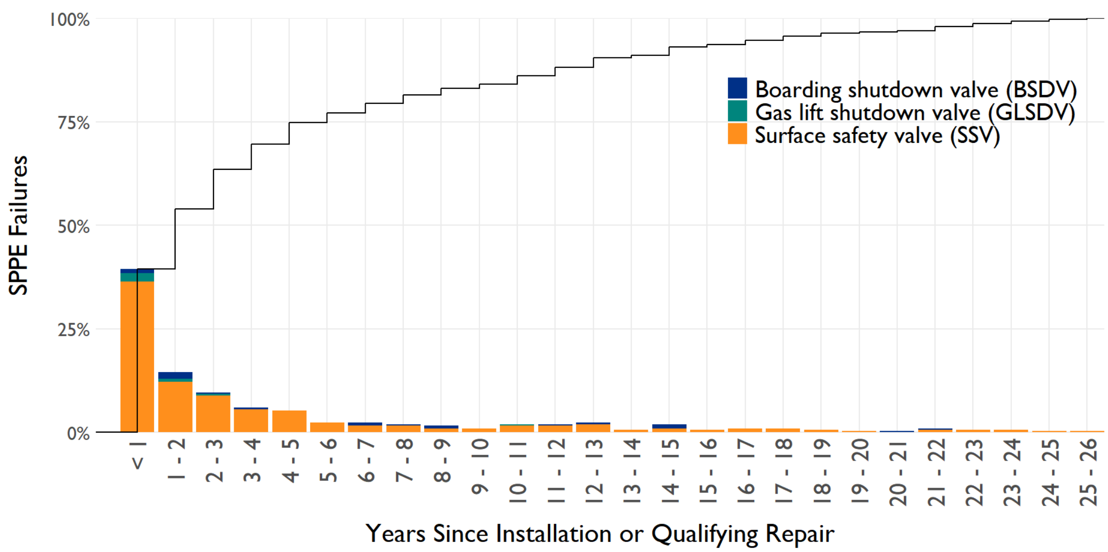
To further explore what constitutes normal wear and tear, an analysis of SPPE time to failure was performed for 2017 to 2023 (see Figure 25 and Figure 26). For 358 failures reported to SafeOCS from 2017 to 2023, the reporter provided either the date of installation or the date of last repair. Reporting of installation or repair date has improved in recent years, reaching 84 percent of events reported to SafeOCS in 2022 and 2023.

For this analysis, the repair date was used as a surrogate for the installation date, i.e., the qualifying repair date, if the repair included replacing the failed components. For example, for a failure of the valve gate and seats, a repair described in the redress history was considered qualifying if it included replacing those components. This analysis of time to failure data is useful for comparing between valve types and gaining insight into reports of wear and tear; however, it should not be interpreted as a measure of average valve life since there are many more (thousands in the case of SSVs and SCSSVs) valves that have not failed and the time to failure is unknown.

The reported dates of installation or qualifying repair ranged from less than one year to 26 years, as shown in the below figures for each valve type. The 357 valves comprised 302 surface valves (270 SSVs, 22 BSDVs, and 10 GLSDVs) and 55 subsurface valves (43 SCSSVs and 11 SSCSVs, and one USV). Surface valves tend to have a shorter time to failure than subsurface valves, with over 50 percent of failed valves being less than two years to failure. This pattern is similar for SSVs, BSDVs, and GLSDVs.

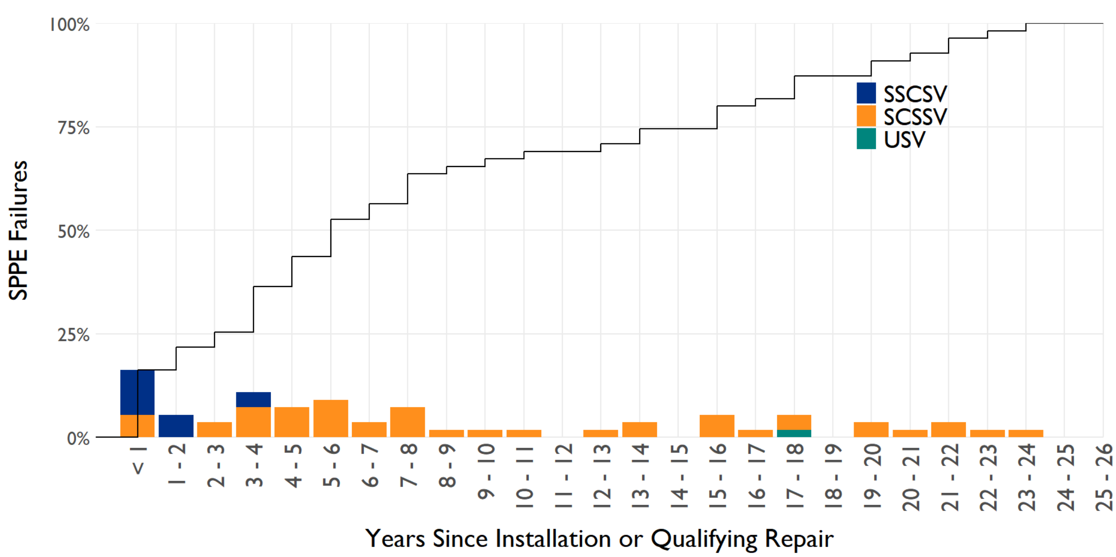
Subsurface valves, comprised primarily of SCSSVs and SSCSVs, tend to have longer time to failure than surface valves, with over half exceeding five years. Most subsurface valves that failed within two years of installation were SSCSVs.

Figure 25: Time to Failure, 2017-2023 (Surface Valves)



NOTE: Percentage is of 302 surface valve failures reported to SafeOCS where the installation date or qualifying repair date was available.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

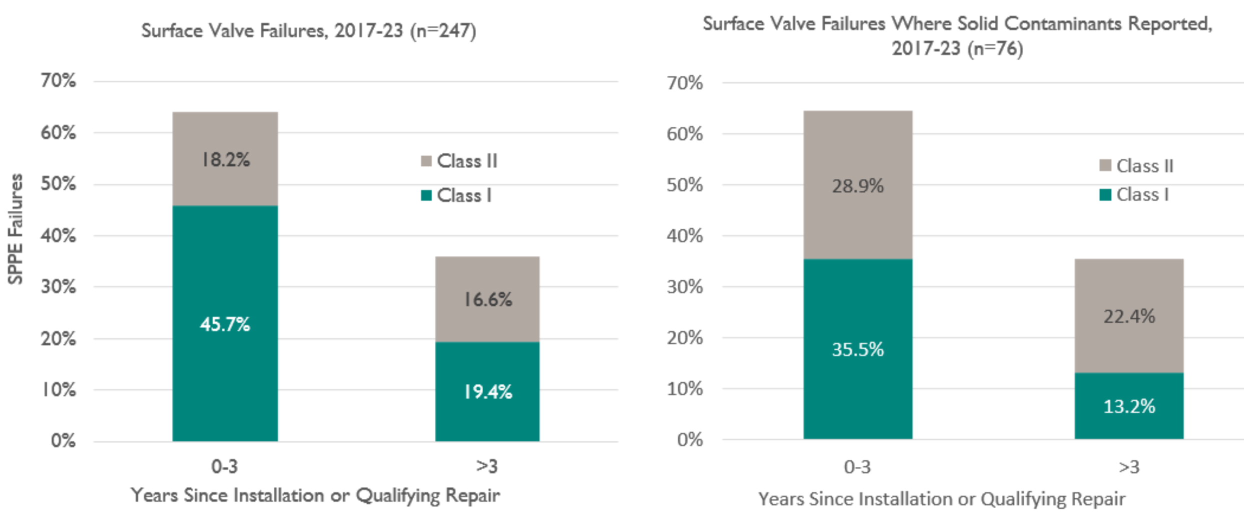
Time to Failure, 2017-2023 (Subsurface Valves)



NOTE: Percentage is of 55 subsurface valve failures reported to SafeOCS where the installation date or qualifying repair date was available.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Regardless of known operating conditions, well rates, and equipment design, the required testing frequency for SPPEs is the same for a given SPPE type. (For example, SSVs are required to be tested monthly. Refer to Table 1 above.) To evaluate whether the earlier-life failures (less than three years) occurred more often on valves exposed to well stream contaminants, BTS examined failures with data on both time to failure and service class. Figure 26 shows the distribution of 247 surface valve failures from 2017 to 2023 that reported both installation or qualifying repair date and the valve service class (left) and the distribution for 76 of these failures that also reported solid well stream contaminants (right). The chart at left shows that more Class 1 valves than Class 2 were involved in earlier-life failures (45.7 percent vs. 18.2 percent from the 63.9 percent of failures during 0-3 years). The chart at right shows that half (51.3 percent) of the failures that also reported solid contaminants (e.g., sand, scale, paraffin) involved Class 2 valves.

Figure 26: Time to Failure and Valve Service Class, 2017-2023



NOTE: Percentage is of surface valve failures reported to SafeOCS with available data on installation or qualifying repair date, service class, and (right panel only) contaminants. Left panel includes 226 SSVs, 4 GLSDVs, and 17 BSDVs, and right panel includes 72 SSVs and four BSDVs.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Repeated Failures

As summarized in Table 6, 10 of the 94 failures reported to SafeOCS were repeated failures, defined in this report as a failure of the same component on the same valve within 12 months. Five different operators reported the 10 events.

Table 6: Overview of 2023 Repeated Failures

	SSV Failures	GLSDV Failure
Number of Failures	9	1
Components Involved	Gate and seats for 7 events, and actuator for 2 events.	Gate and seat.
How Prior Failures Were Corrected	All were repaired, which for gate/seat failures typically means the components were replaced.	Repair.
How Failures Were Corrected	Repair for all events.	Modify.
Event Type	Internal leaks for 7 events and failed to close in two events.	Internal leak.
Detection Method	7 failures were detected during leakage testing, one during ESD testing, and one during normal operations.	Leakage testing.
Root Cause	All were reported as wear and tear.	Design issue.
Contributing Factors	6 events noted valve seat degradation - 1 with improper maintenance or repair and chemical corrosion. One event listed sand cut erosion, which occurred on a Class 1 valve. One event noted atmospheric corrosion, and one event listed no contributing factors.	Improper design, valve seat degradation, and mechanical failure chemical corrosion.

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

In one of the two repeated actuator failures, the diaphragm had been replaced the prior month on the SSV for a well that was completed in 2011. External corrosion was noted as a contributing failure and the valve actuator was repaired again. The reporter indicated that an RCFA had been completed, but the details of the RCFA were not submitted to SafeOCS.

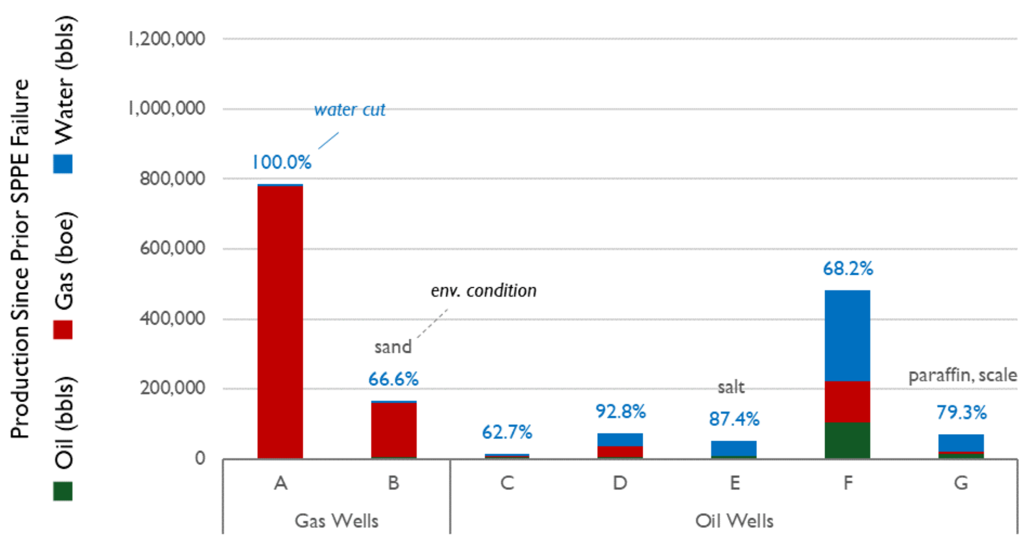
In the other repeated actuator failure, the SSV actuator piston failed after having been replaced approximately three months earlier. The root cause was reported as wear and tear and no formal RCFA was indicated. The reported SSV installation date was in 2010, which coincides with the year of a recompletion on the 40+ year old well.

The GLSDV repeated failure was a failed zero-leakage test (internal leak) just three months after the valve had been rebuilt for the same reason. In the previous failure, the valve had only been rebuilt 13 months prior and was investigated by an OEM technician and the maintenance technician of the operator. They determined that grit had been introduced in the grease used to lubricate the valve seats. Three months after repacking the valve cavity and rebuilding the valve with new gates, seat, and seals, the valve failed the zero-leakage test again. The OEM was involved in the subsequent investigation and rebuild. The materials of construction were modified to address the design issue.

The remaining seven SSV repeated failures were internal leaks. In all cases the valve was rebuilt after the prior repair. There were no RCFAs and no preventive actions reported to SafeOCS. Figure 27 shows the production volumes, environmental conditions, and age of wells with these seven repeated failures where the failed components could have been affected by the well fluids. The production volumes shown reflect the cumulative fluids that passed through the valve from the time of the prior failure until the repeated failure. Similar to prior years, most of the SSV repeated failures with internal leaks were on wells with high water cut (four of seven were ≥75.0 percent water cut), and all had over 60 percent water cut. Two were gas wells (A & B) with water production, which tends to be a harsher environment due to the potential for erosion caused by contaminants carried in the water by the high velocity gas. One of the wells noted sand being present.

Although the estimated valve life for all seven repeated failures was five or more years, two failures occurred on oil wells (columns D and E in Figure 27) completed or recompleted within the last year. Although they show relatively small production volumes, they may have been affected by well completion chemicals or debris introduced during the well workover in addition to having high water cuts.

Figure 27: Production from Wells with Repeated Failures, 2023



NOTE: Includes seven repeated SSV internal leakage failures on seven wells. Excludes two SSV actuator failures, which are not fluid affected and one GLSDV, which does not have production fluids directly from a well flowing through it. Categorization as a gas or oil well determined from OGOR-A product code in the month prior to the failure.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

5 CONCLUSIONS

The objectives of the SafeOCS SPPE failure reporting program are to capture and share essential information about SPPE failures and contribute to an improved understanding of the nature of the failures, including their operating environments and causal factors. This year's report provides more detail about the time to failure for each valve type and the well history for wells involved in repeated failures.

Some general observations can be drawn from the 2023 data and analyses:

- In 2023, none of the known SPPE failures resulted in an HSE event, although there is a pending investigation of a pollution event that may be determined to be an SPPE failure in the future.
- Failures in 2023 returned to near 2021 levels after a lull in 2022 (2021: 214 failures, 2022: 152 failures; 2023: 194 failures), although the active well population continued to decline during that period.
- Generally, production rates per well increased in 2023 as production increased to pre-Covid levels while producing well count fell slightly. The well rates for the wells involved in SPPE failures followed a similar pattern of higher production per well.
- As in previous years, most failures were SSV gate and seat failures (internal leakage) caused by wear and tear and corrected by repairing the valve. For SCSSVs, the most common event type was also internal leakage, with the flapper the most reported failed component.
- An increasing percentage of failure reports indicated the presence of solid contaminants over the past five years.
- Wells with higher GOR and or higher watercut, or both, tended to experience more failures than those with lower GOR or watercut, potentially due to greater presence and velocity of solids in the flow stream.

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.[25] The rule is codified primarily in 30 CFR part 250, subpart H. In September 2018, BSEE published revisions to the 2016 Production Safety Systems Rule, which clarifies provisions for SPPE failure reporting.[26]

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

(a) You must follow the failure reporting requirements contained in section 10.20.7.4 of ANSI/API Spec. 6A for SSVs, BSDVs, GLSDVs and USVs. You must follow the failure reporting requirements contained in section 7.10 of ANSI/API Spec. 14A and Annex F of ANSI/API RP 14B for SSSVs (all incorporated by reference in § 250.198). Within 30 days after the discovery and identification of the failure, you must provide a written notice of equipment failure to the manufacturer of such equipment and to BSEE through the Chief, Office of Offshore Regulatory Programs, unless BSEE has designated a third party as provided in paragraph (d) of this section. A failure is any condition that prevents the equipment from meeting the functional specification or purpose.*

(b) You must ensure that an investigation and a failure analysis are performed within 120 days of the failure to determine the cause of the failure. If the investigation and analyses are performed by an entity other than the manufacturer, you must ensure that the analysis report is submitted to the manufacturer and to BSEE through the Chief, Office of Offshore Regulatory Programs, unless BSEE has designated a third party as provided in paragraph (d) of this section. You must also ensure that the results of the investigation and any corrective action are documented in the analysis report.

(c) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such changes, report the design change or modified procedures in writing to BSEE through the Chief, Office

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

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

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

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

APPENDIX B: RELEVANT STANDARDS

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

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

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

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

APPENDIX C: GLOSSARY AND ACRONYM LIST

Glossary

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

Acid Stimulation: Acid stimulation involves pumping hydrochloric, hydrofluoric, or other acid into a well to dissolve contaminants and improve well productivity.

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

Active Well: A well with SPPE valves providing a barrier to fluids in the reservoir. In general, this means that the well is past the drilling and completion phase, is not undergoing a workover, and has not yet been temporarily or permanently abandoned. It may or may not have production volumes reported during the year, and it may be an injection well or a production well. A well was counted as active if it had an OGOR-A status code other than drilling, abandoned, or well work for at least one month of the year. In 2020, BTS began identifying and counting active wells by the combination of the well's API number and its well completion interval, which means that a dual string well (with both production tubing strings active) was counted as two active wells. Each well production string has its own SPPE valves.

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

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

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

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

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

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

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

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

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

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

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

Gas-Oil Ratio (GOR): The ratio of produced gas to produced oil.

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

High Pressure High Temperature (HPHT): Per 30 CFR 250.804(b), HPHT environment means when one or more of the following well conditions exist: (1) The completion of the well requires completion equipment or well control equipment assigned a pressure rating greater than 15,000 psia or a temperature rating greater than 350 F; (2) The maximum anticipated surface pressure or shut-in tubing pressure is greater than 15,000 psia on the seafloor for a well with a subsea wellhead or at the surface for a well with a surface wellhead; or (3) The flowing temperature is equal to or greater than 350 F on the seafloor for a well with a subsea wellhead or at the surface for a well with a surface wellhead.

Hydrocarbons: Oil and gas.

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

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

Landing Nipple: A completion component fabricated as a short section of heavy wall tubular with a machined internal surface that provides a seal area and a locking profile. Landing nipples are included in most completions at predetermined intervals to enable the installation of flow-control devices, such as plugs and chokes.[27]

Loss of Primary Containment: An unplanned or uncontrolled release of any material from primary containment, including non-toxic and non-flammable materials (e.g., steam, hot water, nitrogen, compressed CO_2, or compressed air).[28]

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

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

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

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

Production Master: See Master Valve.

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

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

[28] International Association of Oil & Gas Producers (IOGP) Report 456, Process safety – Recommended Practice on Key Performance Indicators (Nov. 2018).

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

Repeated Failure: A failure of the same component on the same valve within 12 months.

Tree: See Well Tree.

Water Cut: The ratio of water produced compared to the volume of total liquids produced.[29]

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

Well Completion Interval (or Producing Interval): The designation given to a particular completion zone in a well. This is used to distinguish between the two production tubing strings in a dual completion well.

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 boed 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 boed.

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), which is equal to the barrels of oil plus the barrel oil equivalent of the produced gas. A typical GOM gas conversion factor is 5.62 thousand standard cubic feet of gas is equal to one boe.

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

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

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.[30]

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

Acronym and Abbreviation List

ANSI: American National Standards Institute

API: American Petroleum Institute

APM: Application for Permit to Modify

bbl: barrel

blpd: barrel(s) of liquid (oil plus water) per day

boe: barrel(s) of oil equivalent

boed: barrel(s) of oil equivalent per day

bopd: barrel(s) of oil per day

bwpd: barrel(s) of water per day

BSDV: boarding shutdown valve

BSEE: Bureau of Safety and Environmental Enforcement

BTS: Bureau of Transportation Statistics

cf: cubic feet

CFR: Code of Federal Regulations

CIPSEA: Confidential Information Protection and Statistical Efficiency Act

CO_2: carbon dioxide

DVA: direct vertical access

ESD: emergency shutdown

F: Fahrenheit

FOIA: Freedom of Information Act

GLSDV: gas lift shutdown valve

GOM: Gulf of Mexico

GOR: gas-oil ratio

H_2S: hydrogen sulfide

HPHT: high pressure high temperature

HSE: health, safety, and environment

INC: Incident of Noncompliance

mcf: thousand cubic feet

mcfd: thousand cubic feet per day

mmboe: million barrels of oil equivalent

NTL: Notice to Lessees

OEM: original equipment manufacturer

OCS: Outer Continental Shelf

OGOR-A: Oil and Gas Operations Report – Part A

PMV: production master valve

PWV: production wing valve

RCFA: root cause failure analysis

SME: subject matter expert

SPPE: safety and pollution prevention equipment

SSV: surface safety valve

SCSSV: surface controlled subsurface safety valve

SSCSV: subsurface controlled subsurface safety valve

TUTA: topsides umbilical termination assembly

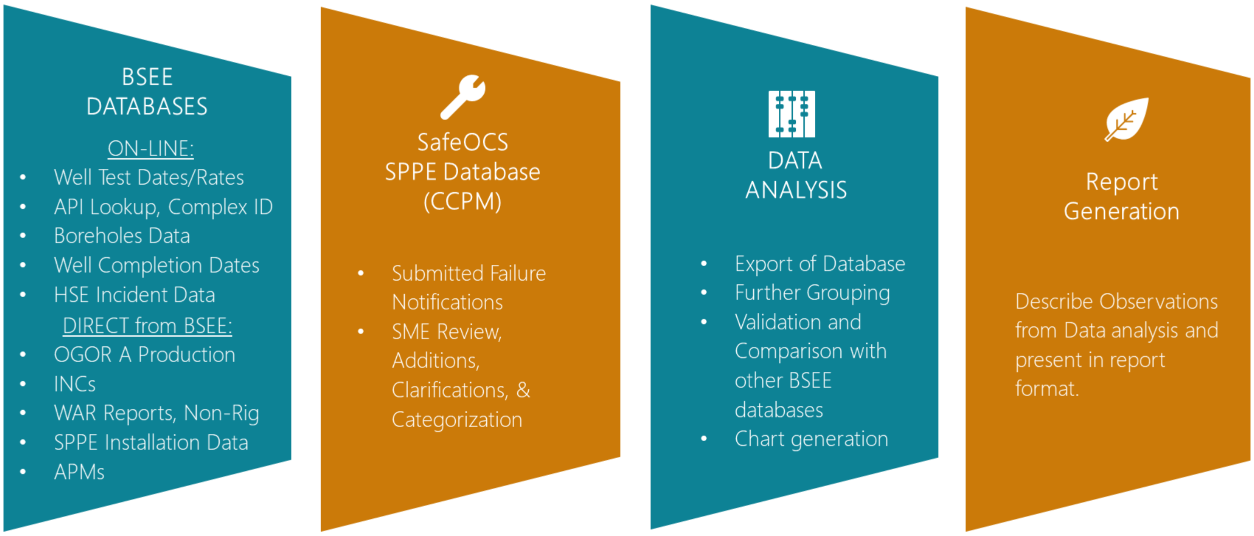
USV: underwater safety valve

WAR: Well Activity Report

APPENDIX D: DATA ANALYSIS METHODOLOGY AND SOURCES

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

Figure 28: SPPE Annual Report Steps



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

WAR and Non-Rig WAR Reports

Operators are required to provide a summary of daily activities in all Outer Continental Shelf (OCS) regions (Gulf of Mexico (GOM), Pacific, and Alaska), reported via Well Activity Reports (WARs)[31] on a weekly basis in the GOM Region and daily in the Pacific and Alaska Regions, per 30 CFR 250.743. The well activities reported in WAR include work accomplished on OCS wells during all phases (drilling, completion, workover, re-completion, non-rig interventions, and abandonment) including any repairs or replacements of subsurface SPPE valves (SSCSVs and SCSSVs).

BTS reviewed the non-rig WAR data to provide context for the SPPE failures reported to SafeOCS. When subsurface safety valves fail, they are often repaired, replaced, or substituted using a non-rig well intervention. The wireline operation reports in the non-rig WARs document these interventions and can sometimes be used to cross-reference the timing and occurrence of subsurface SPPE failures reported to SafeOCS and determine which were reported to SafeOCS.

[31] 30 CFR 250.743.

Application for Permit to Modify (APM)

Operators must submit an APM to BSEE for approval before beginning most well completion, workover, or decommissioning operations.[32] Well intervention operations needed to repair subsurface safety valves are approved by BSEE via APMs. For workover operations, the permits may contain details about SPPE valve inspection, repair, or modification indicating that a failure has occurred. BTS reviewed these to provide additional context for the SPPE failures reported to SafeOCS and identify failures that may not have been reported to SafeOCS. Often, an operation to repair a subsurface safety valve will be described in both APM and WAR data, as the APM describes the plan, and the WAR describes how the plan was implemented. It is not uncommon for an APM to give a history of the well and the failure that occurred with a high-level procedure that is planned to repair the device. In many cases, this history and procedure are not found in other sources and can be invaluable in understanding certain details about the failure.

When considering whether a failure found in an APM was the same as a failure found in another source (e.g., WAR), BTS considered it the same failure if it was the same SPPE valve on the same well completion name (same string on dual well) and the well had not produced since the date of the first reported failure. In those cases, the date of the APM was considered the date of the failure, unless a more specific failure date was provided. In cases where a failure was found only in APM, the failure date was considered the earlier of the APM approval date or the work commence date.

Well Test Reports and Well Production Volumes

Procedures for well production reporting and well test reporting in the OCS regions are codified in BSEE regulations 30 CFR 250 subparts K and L. Subpart L—Oil and Gas Production Measurement, Surface Commingling, and Security describes the measurement and production well testing requirements. Well test reports are based on BSEE procedures which require lessees (i.e., operators) to submit well test volume reports at least semiannually or at a different frequency as approved in the commingling permit for each producing well.[33] During well testing, the well's fluid stream is temporarily segregated from the other wells. While segregated, the oil, gas, and water volumes are measured using flow meters installed on the corresponding streams exiting a three-phase separator, typically called a well test separator, over a specified time (usually four hours). The well test volume (barrels of oil, thousand cubic feet of gas, and barrels of water) are then divided by the test time to establish the well test rate on a per day basis. Well test rates are reported in barrels of oil per day, thousands of cubic

[32] 30 CFR 250.513, 250.613, 250.1712, 250.1721.
[33] 30 CFR 250.1151(a)(2), 250.1204(b).

feet of gas per day, and barrels of water per day. To make comparisons between oil and gas wells, however, these rates are typically converted to barrel of oil equivalents per day (boed) by adding the oil rate to the equivalent gas rate. The equivalent gas rate is equal to the gas volume (in mcf) divided by 5.62.[34] 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 compared it to the most recent well test prior to the failure using well test data from BSEE. Well test rates were used only to validate the well rate range for each well with a reported failure. The well rate range was calculated using the average production for the well (if any) in the month prior to the failure.

Oil and Gas Operations Reports – Part A (OGOR-A)

Operators report well production volume information and well status to the Department of the Interior through OGOR-A submissions. The OGOR-A data provides each well's monthly status, production volumes of oil, gas, and water, and the number of days each well produced during a given month. BTS used the monthly status code to determine whether a well was considered active for purposes of this report and determine the operators associated with active wells. BTS used production volume information to determine the well rate and water cut for active wells and wells with SPPE failures. This information facilitates the comparison of SPPE failures across groups of wells with similar characteristics.

The well rate range for each of the producing wells in the OGOR-A database (including those with a reported SPPE failure) was determined by BTS using the average production rate for each well during the calendar year. The average production rate in boed was calculated by adding each well's total produced oil volume and total gas volume (after converting to boe volume) in the calendar year, and then dividing the sum of those two volumes by the number of days the well was on production that year. A similar method was used to determine each of the well rate ranges for oil, gas, water, total liquids, GOR, and water cut.

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

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[34] 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.

Well Production Time

In addition to each well's produced volumes, the OGOR-A data contains the number of days the well was on production each month. In 2021, a new metric was introduced to characterize the amount of the year that the well produced. Two factors were considered in the new metric, called production time.

The first factor is the number of months during the year that the well had at least one day of production. BTS found that if a well produced at least one day in every calendar month of the year, it was almost always producing the majority of the days in the year. Consequently, this group was labeled "producing all year."

The second factor is the percentage of days in the month that the well was producing. Some wells are produced intermittently because of low reservoir pressure near the well bore. They may be shut-in for several weeks to allow the reservoir pressure near the wellbore to equalize with the higher-pressure area in the reservoir. Then the well is opened to produce again until the pressure near the wellbore is too low to flow naturally, and the cycle is repeated. Separating these intermittent producers from full or part-time continuous producers allowed BTS to compare the failures to the well population to identify whether the production time may have contributed to failures. Wells that did not produce every month in the calendar year were either "not producing," "producing continuously part of the year," or "producing intermittently." Active wells, including wells with SPPE failures, were placed into these four production time groups:

- **Producing all year -** the well produced at least one day in all 12 months of the calendar year.
- **Producing continuously part of the year** – the well produced between one to 11 months, and for the months that there was production, it produced on at least half of the days in the month.
- **Producing intermittently** – the well produced at least one day in at least one but not more than 11 months, and it produced less than half of the days in the months that it produced.
- **Non-producing** – the well did not produce a single day in the calendar year.

Well Status at the Time of Failure

If not provided in the failure report, OGOR-A data was used to determine the well's status at the time of failure:

- If there was no production during the month of failure, then the well's non-producing status was used (oil or gas, depending on the product code for that well).
- If a well had the same producing status code in the month of failure and the month prior to the failure, then that producing well status was used.
- If there was evidence (based on the production volumes, if any, and the days on production) that the well was producing at the time of failure, even if the well status at the end of the failure month was non-producing, then a producing status code was assigned based on the production history for that well (either producing oil completion, producing oil completion with gas-lift, or producing gas completion).
- If there was production in the month of failure but no production the prior month, then the well was assigned a producing status code unless information in the failure report indicated that the well was non-producing at the time of failure.

Incidents of Noncompliance (INCs)

Inspection INCs may be issued by BSEE inspectors whenever they are on a platform and witness deficiencies. For SPPE, such deficiencies could be witnessed during testing as part of an annual inspection. These deficiencies are regulatory violations, and depending on the severity of the violation, BSEE may issue an INC with a warning, component shut-in, or facility shut-in enforcement action. The INC will provide the operator with direction on how to come into compliance and take appropriate action. BTS reviewed INCs issued by BSEE to determine if the deficiency described in the INC was a reportable SPPE failure.[35] The SPPE failures identified in INC data are listed in Table 7. The INCs were then used to cross-reference the SPPE failures during the same period to determine if they were also reported in SafeOCS. While failures associated with INCs do not capture all SPPE failures, the INC database provides an additional source to identify failures in the GOM that may not have been reported to SafeOCS and provides more detail for reported events.

[35] The BSEE Potential Incident of Noncompliance (PINC) List can be accessed at https://www.bsee.gov/reporting-and-prevention/potential-incident-of-noncompliance-pinc.

Table 7: Count of SPPE Failures Identified in INC Data, 2019-2023

PINC	Short Description	2019	2020	2021	2022	2023
E-100	Unauthorized discharge of pollutants into sea	0	0	0	1	0
G-111	SPPE corroded or leaking and needing repair	0	3	0	5	2
G-112	SPPE leaking hydrocarbons externally	0	1	0	0	0
G-113	Lessee makes facilities available for inspection	0	0	1	0	0
G-115	Testing not able to be completed due to SPPE failure to open	0	0	0	0	1
G-132	Failed to notify district manager of safety system damages	0	0	0	0	1
P-102	Shutdown valve failed to close in required timing upon receiving signal	3	0	3	1	7
P-103	SPPE bypassed or blocked out of service	0	2	0	1	0
P-104	Failure to maintain the hydraulic system operating condition	0	0	0	3	0
P-240	SCSSV was not tested every 6 months	12	5	4	5	5
P-241	SCSSV failed to close within 2 minutes	18	0	10	11	0
P-261	Long term shut-in well SCSSV rendered inoperable	0	1	1	0	1
P-280	SSV failed to close within 45 seconds	16	16	4	5	9
P-281*	SSCSV not removed, inspected, and repaired or adjusted at 6 or 12 months.	0	0	0	1	4
P-283*	Tubing plug not tested for leakage every 6 months.	0	0	0	1	0
P-307	SSV was not tested monthly	1	2	0	2	0
P-319	BSDV was not tested monthly	0	1	1	4	0
P-366	Departing subsea gaslift line equipped with GLSDV	0	0	2	0	2
P-408	SPPE failed to test with certification requirements	0	0	0	0	1
P-412	SSV, USV, or BSDV had internal leakage	38	13	22	21	24
	Total	**88**	**44**	**48**	**61**	**57**

NOTE: *Safety valve leaks were mentioned in the description for these INCs.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Incident Reports

Operators are required to report incidents, spills, and pipeline damage information to BSEE under the regulations.[36] These incidents may involve, for example, releases of gas or fluids to the environment. In some cases, an SPPE valve failure was a factor in the reported incident. BTS reviewed the incident data for events involving SPPE failures and cross-referenced that data with the set of events reported to SafeOCS to build a more complete dataset.

Boreholes Data

Operators report to BSEE various information about OCS boreholes (i.e., the hole drilled for reservoir exploration or installation of a production well), such as location and depth information. The water depth for active wells and wells with SPPE failure in the GOM OCS was determined using boreholes

[36] 20 CFR 250.186–250.190, 250.1008(e), 254.46. See also BSEE Notice to Lessees No. 2019-N05, Incident and Spill Reports.

data provided by BSEE. The boreholes table includes a water depth field, which was joined with the well API number to determine the water depth for active wells. This information facilitates the comparison of SPPE failures across groups of wells with similar characteristics.

Well API Number

In cases where the well API number was not reported on the SafeOCS notification, BTS utilized the BSEE Data Center API lookup and the OGOR-A production data to determine the well API number associated with each SPPE failure based on other information provided such as lease number, well name, and complex ID. Since GLSDVs and BSDVs are often associated with multiple wells, multiple API well numbers were assigned to those failures.

Well Count Determination from OGOR-A Data

The total GOM OCS well count was determined using production data from OGOR-A data. Each well is identified with an API number and a completion interval, and each interval has a reported well status code each 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:

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

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

APPENDIX E: OPERATION OF SPPE VALVES

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

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

The SSCSV is a normally open valve in the well's tubing that closes at a predetermined flow rate or pressure. The SSCSV is installed or removed (i.e., run or pulled) using a wireline and typically set in a landing nipple in the well's tubing string.[37] The valve is typically held open by a spring. The differential pressure across the valve causes it to close and stop the well from flowing at flow rates higher than the designed shutdown rate. Alternatively, the SSCSV may be a dome pressure design (e.g., a PB valve) that uses charged pressure to allow the valve to close once the tubing pressure at the valve falls below a predetermined value. Both SSCSV types can be retrieved for maintenance or to allow for other downhole operations. SSCSVs may be used in surface wells but are no longer allowed in new subsea wells, as mentioned above.

[37] A landing nipple is a type of completion component that provides a seal area and a locking profile. See Appendix C for full definition.

APPENDIX F: TYPICAL SPPE VALVE COMPONENTS

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

Table 8: Typical SPPE Valve Components

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

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

Appendix G: 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 is an event that results in consequences to health, safety, or the environment above a specified threshold, as detailed below. See also BSEE HSE incident reporting requirements at 30 CFR 250.188, 30 CFR 254.46, and NTL No. 2019-N05.

- 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 bbl)
- 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 >1 barrel

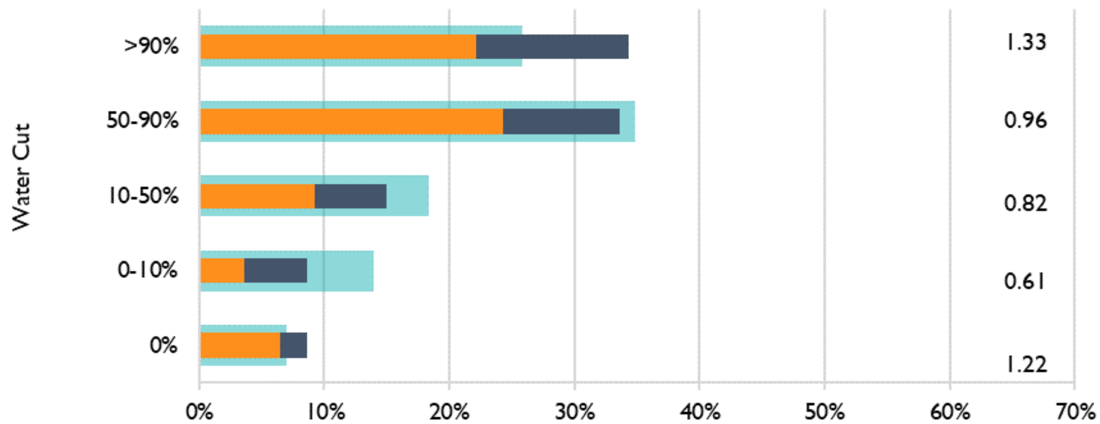
Appendix H: Additional Tables and Figures

The following charts are provided for 2023 failures to allow comparison to the 2022 annual report.

Water Cut Range

A well's water cut is its ratio of produced water to total produced liquids (oil plus water). Figure 29 shows the failures in each water cut group as compared to the producing well population. The groups with the highest number of failures were the highest and lowest water cut groups (the >90 percent and zero water cut groups).

Figure 29: SPPE Failures and Active Wells by Water Cut Range, 2023



	0%	0-10%	10-50%	50-90%	>90%
Well Population	7.0%	14.0%	18.3%	34.9%	25.8%
Surface Valve Failures	6.4%	3.6%	9.3%	24.3%	22.1%
Subsurface Valve Failures	2.1%	5.0%	5.7%	9.3%	12.1%

NOTES:

1. Active wells: n=2,425. Includes producing wells only. Rate is taken from 2023 annual average.
2. Wells with SPPE failure: n=140. Includes failures on producing wells where produced fluids could have been a factor in the failure and well rates indicated the well produced in the month prior to the failure.
3. Actual to expected failure ratio (at right) = percent of SPPE failures (surface + subsurface) / percent of active wells.

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

Valve Certification

SPPE certifications fall under four types (Table 9). The Production Safety Systems Rule requires that SPPE be certified to ANSI/API Spec. Q1.[38] BSEE may exercise its discretion to accept and approve SPPE certified under other quality assurance programs. ANSI/ASME SPPE-I was a previous standard (beginning in 1996) containing certification criteria.[39] Based on the dates of the certification standards, one could expect to see fewer and fewer failed valves being SPPE-1 certified and more being Spec Q1 certified. Generally, that is the case. SafeOCS lacks the certification type for the population of active valves, which would be necessary to determine whether a disproportionate number of failures occurred with a specific certification type.

Of failures reported to SafeOCS in 2023, five were reported as non-certified. Those five, plus three of the six 2023 failures that did not include certification information, were reported as classed valves per API standards. The 11 valves with incomplete certification information include one SCSSV installed in 2005 and three BSDVs installed in 2002, 2008, and 2019. The remaining seven were SSVs installed between 2011 and 2018.

Table 9: Certification Status of Reported SPPE, 2017-2023

SPPE Certification	2017	2018	2019	2020	2021	2022	2023
Newly installed certified SPPE pursuant to ANSI/API Spec. Q1	13.9%	12.7%	14.7%	16.8%	34.2%	34.8%	51.6%
Newly installed certified SPPE pursuant to another quality assurance program	6.1%	1.0%	0.0%	1.0%	3.5%	1.4%	0.0%
Previously certified under ANSI/ASME SPPE-1	69.6%	77.0%	71.6%	71.3%	45.6%	53.6%	36.8%
Non-certified SPPE	0.9%	0.5%	2.2%	2.0%	2.6%	0.0%	5.3%
Not answered	9.6%	8.8%	11.6%	8.9%	14.0%	10.1%	6.3%

NOTE: Includes failures reported to SafeOCS. Excludes failures found only in other sources.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

[38] Certified equipment installed prior to the inception of ANSI/API Spec. Q1 2013 should choose Previously certified under ANSI/ASME SPPE-1.
[39] The original ASME SPPE-1 certification standard was first released April 1, 1985. There have been many revisions and addendums added to the original standard over the years, including the last one on April 30, 1996.