OIL AND GAS PRODUCTION SAFETY SYSTEM EVENTS

2020 ANNUAL REPORT

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

2020 Annual Report

Oil and Gas Production Safety System Events

U.S. Department of Transportation
Bureau of Transportation Statistics

ACKNOWLEDGEMENTS

Bureau of Transportation Statistics

Patricia Hu

Director

Rolf Schmitt

Deputy Director

Produced under the direction of:

Demetra Collia

Director, Office of Safety Data and Analysis

Recommended Citation:

Bureau of Transportation Statistics. *Oil and Gas Production Safety System Events – 2020 Annual Report.* Washington, D.C.: United States Department of Transportation, 2020.

https://doi.org/10.21949/1523057

Cover Image Source: Offshore oil rig and platform. ©Quimey - stock.adobe.com.

Quality Assurance Statement

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

Notice

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

TABLE OF CONTENTS

Acknowledgements i

Quality Assurance Statement ii

Table of Contents iii

List of Figures v

List of Tables vi

Executive Summary 1

1 Introduction 1

About SafeOCS 1

Data Adjustments 2

2 Safety and Pollution Prevention Equipment (SPPE) 3

Location of SPPE Valves 3

How Valve Types Are Grouped in this Report 5

Purpose and Operation of SPPE Valves 5

3 Data Collection and Validation 7

Data Confidentiality—CIPSEA 7

SPPE Failure Reporting Form Enhancements 7

Data Validation and Exposure Measures 8

4 Data Analysis 11

SPPE Numbers at a Glance 11

Production During the COVID-19 Pandemic 12

Completeness of Failure Event Reporting 14

Who Reported Equipment Events 16

Details of Reported Equipment 17

Failures and Potential Consequences 21

Well Location and Status 23

Well Fluid Rates 26

SPPE Pressure and Temperature Rating 39

How Failures Were Detected 39

How Failures Were Addressed 40

Root Causes and Contributing Factors of Failures 43

Repeated Failures 49

5 Conclusions and Next Steps 51

Next Steps: Opportunities for Improvement 52

Appendix A: Oil and Gas Production Safety Systems Rule Background Information 53

Appendix B: Relevant Standards 55

Appendix C: Glossary and Acronym List 56

Appendix D: Data Analysis Methodology 63

Appendix E: Typical SPPE Valve Components 68

Appendix F: HSE Incidents 69

LIST OF FIGURES

Figure 1: Equipment Schematics 4
Figure 2: GOM Production, 2018-2020 13
Figure 3: GOM Production Hours Worked, 2017-2020 13
Figure 4: Sources of SPPE Failure Records, 2020 14
Figure 5: Reported SPPE Failure Events by Operator, 2020 16
Figure 6: Active Wells and Reporting Status of Operators, 2017-2020 16
Figure 7: Reported SPPE Events by Valve Type, 2020 17
Figure 8: Failed Components in SPPE Valves, 2020 19
Figure 9: Event Type in Order of Significance, 2020 21
Figure 10: Failure Events by Type, 2017-2020 (SafeOCS Failures Only) 23
Figure 11: Status of Production Wells, December 2020 24
Figure 12: Status of All Production Wells vs. Wells with SPPE Failure, 2020 25
Figure 13: Reported SPPE Failure Events by Operator and Well Status, 2020 26
Figure 14: Well Rates for All Wells vs. Wells with SPPE Failure, 2020 27
Figure 15: Type of Reported Failures by Well Rate, 2020 28
Figure 16: Failures Grouped by Well Fluid Rate Ranges, 2020 29
Figure 17: Gassy and Oily Wells Based on GOR, 2020 30
Figure 18: SPPE Failures and Producing Wells by GOR Range, 2020 31
Figure 19: SPPE Failures and Active Wells by Gas Rate Group, 2020 32
Figure 20: SPPE Failures and Active Wells by Oil Rate Group, 2020 33
Figure 21: SPPE Failures and Active Wells by Water Rate Groups, 2020 34
Figure 22: SPPE Failures and Active Wells by Water Cut Range, 2020 35
Figure 23: SPPE Failures and Active Wells by Total Liquid Rate, 2020 36
Figure 24: Gas Rate versus Liquid Rate, 2020 37
Figure 25: GOR versus Liquid Rate, 2020 38
Figure 26: Percent of Failures by Valve Pressure and Temperature Ratings, 2020 39
Figure 27: Failure Detection Methods, 2020 40
Figure 28: Reported Corrective Actions, 2020 40
Figure 29: SPPE Components Repaired, 2020 41
Figure 30: Reported Corrective Actions, 2017-2020 (SafeOCS Failures Only) 42
Figure 31: Root Causes of Reported Failure Events, 2020 43
Figure 32: Factors Contributing to Equipment Failures, 2020 44

Figure 33: Factors Contributing to Equipment Failures, 2017-2020 (SafeOCS Failures Only) 45
Figure 34: Well Stream Contaminants, 2020 46
Figure 35: Time to Failure, 2017-2020 47
Figure 36: Time to Failure and Valve Service Class, 2017-2020 48
Figure 37: Production from Wells with Repeated Failures, 2020 50
Figure 38: SPPE Annual Report Steps 63

LIST OF TABLES

Table 1: Typical SPPE Testing Frequency and Leakage Allowance 5
Table 2: SPPE Numbers at a Glance 12
Table 3: SPPE Failure Rates in the Gulf of Mexico, 2019-2020 18
Table 4: Chi-Square Test Comparing 2019 and 2020 Failure Rates 19
Table 5: Certification Status of Reported SPPE, 2020 20
Table 6: Distribution of SPPE Failures by Water Depth, 2020 23
Table 7: Overview of 2020 Repeated Failures 49
Table 8: SPPE Failures Identified in INC Data, 2020 66
Table 9: Typical SPPE Valve Components 68

EXECUTIVE SUMMARY

The *2020 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.

The coronavirus pandemic was a significant factor in an overall decrease in both event reporting and oil and gas production levels in 2020. SafeOCS received 101 SPPE failure notifications for 2020, and an additional 71 failure events were identified in other data sources, bringing the total number of known SPPE failure events in 2020 to 172, a 50.9 percent decrease from 2019. Reporting of SPPE events to SafeOCS appears to be incomplete, as 41.3 percent of distinct failure events (71 of 172) were not reported to SafeOCS. The number of active wells decreased by 5.2 percent in 2020 compared to 2019, and total average daily production decreased 11.9 percent. While the number of reporting operators (14) remained the same from 2019 to 2020, the number of active operators fell from 53 to 46.

Valve Types and Failure Rates

Surface safety valves (SSVs) and surface controlled subsurface safety valves (SCSSVs) had the highest proportions of failures in 2020, comprising 66.0 percent and 30.2 percent of failures with known valve type, respectively.[1] No underwater safety valve (USV) or subsurface controlled subsurface safety valve (SSCSV) failures were reported among the failures with known valve type. In 2020, approximately 11,690 SPPE valves were in service in 5,715 active wells in the GOM OCS. The failure rates were under 0.7 percent for each valve type, decreasing since 2019.

Potential Consequences of Failures

SPPE failures were categorized based on the extent to which they degrade the installed well safety systems and pose potential consequences to personnel and the environment. None of the failures in 2020 were characterized as health, safety, or environmental (HSE) incidents, i.e., an event that results in consequences to the health or safety of personnel or the environment above a specified threshold.[2] Three external leaks of produced hydrocarbons were reported, each involving small leaks of well fluids

[1] Percentages are of 159 total failures. Excludes 13 failures of subsurface safety valves identified in OGOR-A data where it could not be determined whether they were SCSSVs or SSCSVs.
[2] See Appendix F for additional detail on the definition of an HSE incident.

to the atmosphere. Most SPPE failures (75.5 percent of the failures 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. Internal leaks generally pose less risk than other types of failures, such as external leaks or the valve failing to close.

Characteristics of Wells with SPPE Failures

About 69.3 percent of SPPE failures in 2020 occurred on producing wells.[3] Over three quarters of the failures (84.2 percent) occurred on wells producing less than 500 barrels of oil equivalent per day (boed), and more than half (57.1 percent) occurred on wells producing less than 100 boed. These lower-producing wells pose less risk than higher-producing wells. About 2.4 percent of failures were associated with wells producing more than 5,000 boed. The most significant event type among higher-producing wells (>1,000 bopd or mcfd) was failure to close when commanded, totaling five events, four of which were failures of tubing-retrievable SCSSVs. Wells with higher gas-oil ratio (GOR) (2,000 cf/bbl and above) experienced more failures in 2020 relative to wells with lower GOR.

Root Causes and Contributing Factors of Failures

As with previous years, wear and tear was the most frequently reported root cause, listed for 79.2 percent of failures reported to SafeOCS. Valve seat degradation was the most reported factor contributing to SPPE failures, reported for 67.5 percent of the events where information on contributing factors was available, followed by factors related to the operating environment including sand cut erosion, atmospheric or chemical corrosion, paraffin, debris, and scale, which were reported for 36.4 percent of these events. An analysis of contributing factors each year from 2017-2020 showed that valve seat degradation was more frequently reported for surface valves, while solid contaminants were more frequently reported for subsurface valve failures. To further explore what constitutes normal wear and tear, BTS examined the time to failure for 124 valves that failed from 2017-2020 where the date of valve installation was available (110 surface valves and 14 subsurface valves). Half failed within one year, and nearly three quarters (73.4 percent) failed within three years.

Next Steps

The implementation of a revised failure reporting form in 2020 is expected to lead to better quality of information. BTS continues to focus on improving data quality and accessibility, including potential improvements to exposure data and measures, as well as ways to share learnings with stakeholders.

[3] Calculation excludes one failure on an injection well and five failures of GLSDVs or BSDVs, which can serve multiple wells producing into a common subsea flowline. See Figure 12.

1 Introduction

The *2020 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

The Department of Transportation's Bureau of Transportation Statistics (BTS), a principal federal statistical agency, entered an interagency agreement with the Department of the Interior's Bureau of Safety and Environmental Enforcement (BSEE) to develop, implement, and operate the SafeOCS program. SafeOCS is a confidential reporting program that collects and analyzes data to advance safety in oil and gas operations on the OCS. The program's objective is to capture and share essential information across the industry about accident precursors and potential hazards associated with offshore operations. The Confidential Information Protection and Statistical Efficiency Act (CIPSEA) protects the confidentiality of all data submitted directly to SafeOCS.[4]

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 specified in API standards and submit failure reports to both BTS, as BSEE's designated third party to receive this information, and the original equipment manufacturer.[5] This is the fourth annual report on the SPPE failure reporting program.

Contributors to this report include subject matter experts retained by SafeOCS 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.

[4] Confidential Information Protection and Statistical Efficiency Act of 2018, Pub. L. No. 115-435, tit. III (reauthorizing the 2002 law of the same name).
[5] See appendices A and B for additional detail on the regulatory requirements for SPPE failure reporting.

Data Adjustments

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

- 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 results reflect the current methodology.

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) protects personnel and the environment by controlling the flow of well fluids (crude oil, natural gas, and water), especially in case of an emergency or system failure.[6] 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:[7]

- 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)

Location of SPPE Valves

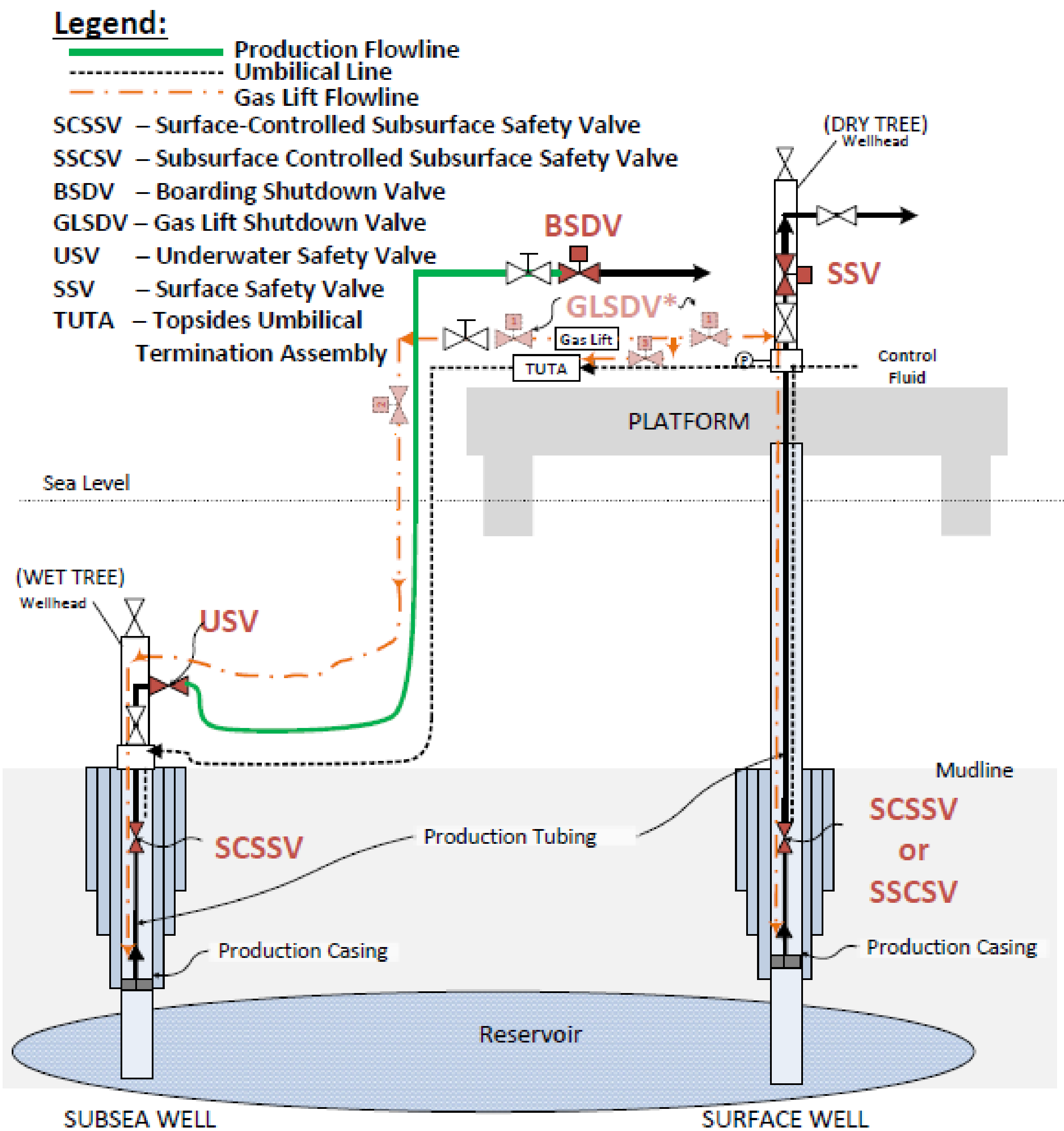
SPPE valves are found in both surface wells and subsea wells. Surface wells have dry trees or direct vertical access (DVA) trees located above sea level on top of the well. Their location allows the operator direct access to the wellbore from the production platform. Subsea wells have wet trees located 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.[8] They provide redundancy in the equipment to allow for

[6] The rule is codified primarily in 30 CFR part 250, subpart H. The failure reporting requirement is codified in 30 CFR 250.803.
[7] 30 CFR 250.801.
[8] 30 CFR 250.833.

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

Figure 1: Equipment Schematics



NOTE: GLSDVs for subsea wells may be installed in 1 of 3 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 typically refers to valves installed below the mudline, USVs are included with subsurface valves because they are installed below the water's surface.

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

Table 1: Typical SPPE Testing Frequency and Leakage Allowance

Valve	Allowable Leakage Rate	Testing Frequency
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. DOT, BTS, SafeOCS Program.

Purpose and Operation of SPPE Valves

SPPE valves are operated in the open position to allow the production from the well to flow. They are designed to close automatically if a control system failure occurs (i.e., fail-safe valves) or if there is an operational need to stop the flow from the well. All SPPE valves are considered isolation valves and mechanical barriers because they are designed to stop the flow of well fluids to protect personnel, equipment, and the environment. In general, the main valve component moves from an open to a closed position, where it contacts the valve seat to seal off the internal flow in the pipe or tubing. All SPPE

[9] 30 CFR 250.873, 250.880.
[10] Additional information and requirements for new wells and wells that are completed and disconnected from monitoring capability are provided in the CFR.

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

Most SSVs and USVs are sliding gate valves operated either hydraulically (using hydraulic oil pressure) or pneumatically (using gas pressure). SSVs are found on surface wells (on dry trees), whereas USVs are located on subsea wells (on wet trees). BSDVs, utilized for flowlines of subsea wells and located on the platform, are commonly gate or ball valves. Similarly, GLSDVs are either gate or ball valves, and are most 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.[11] 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.

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

3 Data Collection and Validation

Data Confidentiality—CIPSEA

The Confidential Information Protection and Statistical Efficiency Act (CIPSEA) 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 regulatory purposes. Information submitted under this statute is protected from release to other government agencies, including BSEE, and from Freedom of Information Act (FOIA) requests, subpoenas, and legal discovery.

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.

SPPE Failure Reporting Form Enhancements

Operators use the SafeOCS SPPE Failure Notification Form, available on the SafeOCS website, to report SPPE failure events. In December 2020, SafeOCS released a revised version of the form to improve data quality, data collection consistency, and analysis and identification of learnings. Virtual training sessions were held with representatives from the industry to help explain the form changes. The specific form enhancements included the following:

- Distinguished failure types (external leak, internal leak, failure to close, and failure to open) from contributing factors as separate sections of the form.
- Clarified failure type definitions to better distinguish among failure to close when commanded, failure to close in required timing, and internal leak (i.e., failed leakage test when closed).
- Added additional drop-down selections to capture well contaminant information better.
- Changed the selection "activated in response to ESD" to "activated in response to ESD testing" to better distinguish between failures detected during emergency response versus emergency shutdown (ESD) system testing. An additional selection covers activation during emergency conditions.
- Replaced the question "Was the well shut-in at the time of the failure?" with "What was the well status at the time of this failure?" with appropriate drop-down selections. This was done to improve information and distinguish between a well already shut-in at the time of failure versus a

well shut-in as a response action.

- Clarified and simplified corrective action definitions.
- Added fields for installation date and repair date to improve capture of SPPE time to failure information.
- Added a question to specify where the SSCSV was installed, which affects its required testing frequency, to improve information on SSCSV failures.
- Added questions to specify the type and volume of fluid that leaked to improve information on external leaks.
- Revised selection options to improve information about root causes and contributing factors.
- Added fields to allow for reporting of all wells associated with an SPPE valve to improve well information for GLSDVs and BSDVs that serve multiple wells. Previously the form allowed for entry of only one well.

These form enhancements required corresponding changes to the SafeOCS SPPE database fields and selection options. BTS completed a data migration for all existing SPPE failure records to align them to the new database requirements and allow new and old records to be compared and included in the same analyses. Where insufficient information was available to populate a new data field for a legacy record (i.e., an event report submitted using the older form), the data field was left blank. As the new form was introduced in late 2020, there is insufficient data for some of the new data fields to properly aggregate and analyze. Where sufficient data was available, it was analyzed and considered in the development of this report.

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 its functional specifications and characteristics 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, including another source of BSEE data added to the analysis in 2020—Application for Permit to Modify (APM) data, which pertains to well work applications submitted to BSEE. Appendix D provides more information about the methodology used in evaluating each data source.

Applications for Permit to Modify (APMs)

Operators are required to obtain an approved APM from BSEE before beginning completion, workover, or abandonment work on a well. For workover operations, the permits may contain details about SPPE valve inspection, repair, or modification that indicate that a failure has occurred. BTS reviewed the APM details to cross-reference the timing and occurrence of SPPE failures and determine which were reported to SafeOCS. As the operators use APMs to request permission from BSEE to modify an active well for repair or enhancement purposes, they typically are the precursor for any work performed on a well. It's not uncommon for the APM(s) to give a history of the well and the failure with a high-level procedure planned to repair the device. In many cases, this history and the proposed repair procedure are not found in other sources and can be invaluable in understanding certain details about the failure.

Borehole Data

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

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 used the INCs involving 2020 SPPE failures to cross-reference and validate SPPE failures reported to SafeOCS during the same period and potentially further enhance the quality of information collected. While failures associated with INCs do not capture all possible failures that occur, the INC database provides an additional source to identify failures in the GOM that may not have been reported to SafeOCS and provide more detail for reported events.

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 those 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.

In addition to well production volume, 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.

SPPE Installation Data

Operators report SPPE valve installations to BSEE through the production safety system permit process. These are captured in a database that includes valve data such as type of valve, location, and installation date. BTS used SPPE installation data to estimate the total number of SPPE valves associated with wells in the GOM and to calculate the denominators for SPPE failure rates.

Well Activity Reports (WARs)

Operators are required to provide to BSEE a summary of daily well activities via WARs.[12] The well activities reported in the WARs include work accomplished on OCS wells during all phases (drilling, completion, workover, recompletion, non-rig interventions, and abandonments), including any repairs or replacements of SPPE valves. BTS reviewed the WAR reports for non-rig operations (e.g., wireline operation reports) to cross-reference the timing and occurrence of SPPE failures and determine which were reported to SafeOCS.

Well Test Reports

BSEE requires operators to submit well test reports detailing daily oil, gas, and water volumetric rates at least once every six months for each producing well.[13] Well test rates are reported in barrels of oil per day, thousands of cubic feet of gas per day, and barrels of water per day. BTS reviewed well test reports to provide context for each failure's potential impact by comparing the well test rates to the production rates calculated from volumes reported in OGOR-A data.

---

[12] 30 CFR 250.743.

[13] Procedures for OCS well test reporting are codified in 30 CFR part 250 subparts K and L.

4 Data Analysis

SPPE Numbers at a Glance

Subpart H covers production operations on the Outer Continental Shelf (OCS), which includes BSEE's Gulf of Mexico (GOM), Pacific, and Alaska regions. For 2020, SafeOCS received equipment failure notifications for operations in the GOM only, which accounts for over 99 percent[14] of all offshore production in the United States. The exact locations of reported equipment failures are not disclosed in this document to protect the data's confidentiality.

SafeOCS received 101 SPPE failure notifications for 2020, a 55.1 percent decrease from 2019. An additional 71 failure events were identified in other sources (APM, INC, OGOR-A, or WAR data), bringing the total number of known SPPE failure events in 2020 to 172, a 50.9 percent decrease from 2019. In general, analyses presented in this report consider all known failure events to the extent practicable. However, failures found in non-SafeOCS data sources 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 2020 compared to the previous three years. The 101 failures occurred on 90 of 5,715 total active wells (1.6 percent) in the GOM OCS.[15] Most of those failures (96.0 percent) were on valves accessible from the platform where they can be addressed more quickly, reducing potential safety and environmental risk.[16] Only four of the eight failures that occurred on subsea wells, the SCSSV failures, would require an intervention vessel to address. The number of active wells was lower than in 2019, and production decreased from an average of 2.74 mmboe/day (1,001 mmboe total for 2019) to 2.41 mmboe/day (884 mmboe total for 2020). The number of reporting operators (operators who reported failure notifications) remained the same in 2020 at 14 operators in the GOM. Reporting operators contributed 57.8 percent of oil and gas production from 58.0 percent of active wells, both decreases from 2019.

[14] BSEE Data Center, Outer Continental Shelf Oil and Gas Production data, December 2020 volumes.
[15] 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.
[16] Includes failures on surface wells, plus failures of BSDVs and GLSDVs on subsea wells.

Table 2: SPPE Numbers at a Glance

		2017	2018	2019	2020
Operator Summary[1]	Active Operators	56	56	53	46
	Producing Operators	55	51	50	43
	Reporting Operators (Pct. of Active Operators)	8 (14.3%)	14 (25.0%)	14 (26.4%)	14 (30.4%)
	Reporting Operators' Pct. of Active Wells	35.2%	70.6%	59.4%	58.0%
	Reporting Operators' Pct. of Production	56.6%	66.6%	75.7%	57.8%
	Reporting Operators' Pct. of Production Work Hours	44.6%	58.5%	74.4%	61.9%
GOM Well Production Summary[2,3]	Active Wells	6,446	6,231	6,029	5,715
	Wells with SPPE Failure	99 (1.5%)	162 (2.6%)	184 (3.1%)	90 (1.6%)
	Daily Prod. - Total Active Wells (boed)	2,206,049	2,242,236	2,741,291	2,414,434
	Daily Prod. - Wells with SPPE Failure (boed)	44,136 (2.0%)	61,598 (2.7%)	76,934 (2.8%)	72,146 (3.0%)
SPPE Population	Installed SPPE Valves	12,373	12,174	11,849	11,690
SPPE Failure Summary[4]	Total Distinct SPPE Failures	212	266	350	172
	SPPE Failures Reported to SafeOCS	**112**	**204**	**225**	**101**
	SPPE Failures Identified from Other Sources	100	62	125	71
	Pct. of Failures Not Reported to SafeOCS	47.2%	23.3%	35.7%	41.3%
SafeOCS Failures Only — **Tree Types**	Surface Well SPPE Failure Events	106	195	210	93
	Subsea Well SPPE Failure Events	4	7	15	8
	SPPE Failure Events with Unknown Tree Type	2	2	0	0
SafeOCS Failures Only — **Event Types**[5]	HSE Incident	0	0	0	0
	External Leak of Hydrocarbons	2	3	5	3
	Failed to Close When Commanded	13	16	22	11
	Internal Leak	99	159	199	80
	Failed to Close in Required Timing	0	14	0	1
	Failed to Open	3	6	5	4
	External Leak of Control Fluids	0	10	5	4

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

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 this revised methodology.

3 Wells with SPPE failure and daily production rate for wells with SPPE failure consider only failures reported to SafeOCS.

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

5 Total may exceed count of SafeOCS failures because more than one event type can apply to a single failure.

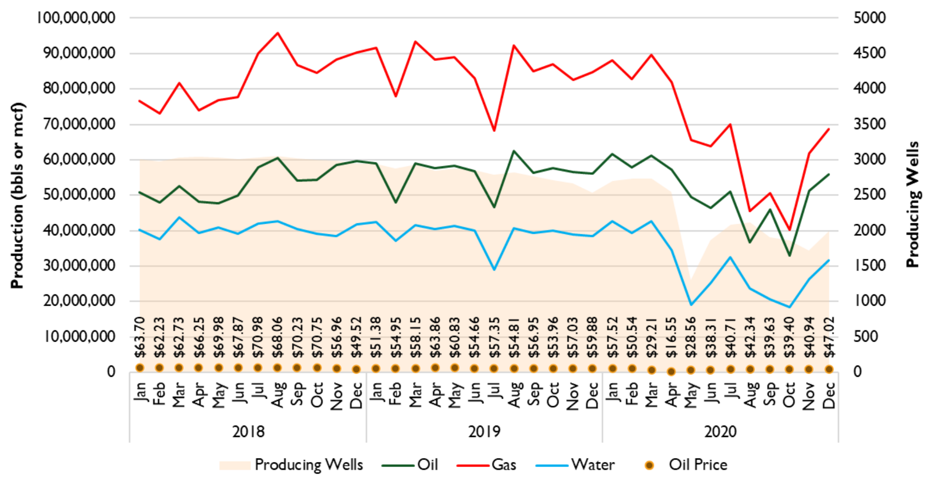
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Production During the COVID-19 Pandemic

The coronavirus pandemic was a significant factor in the overall decrease in both event reporting and oil and gas production levels in 2020, as reflected by the sharp decrease in production levels in the second quarter, when the pandemic slowed the economy dramatically (Figure 2). Demands on the U.S. transportation system fell significantly, with schedules and ridership for commercial airlines, rail, and transit systems dropping to record lows as passenger travel declined.[17] These rapid changes increased uncertainty in the upstream demand for fuel.

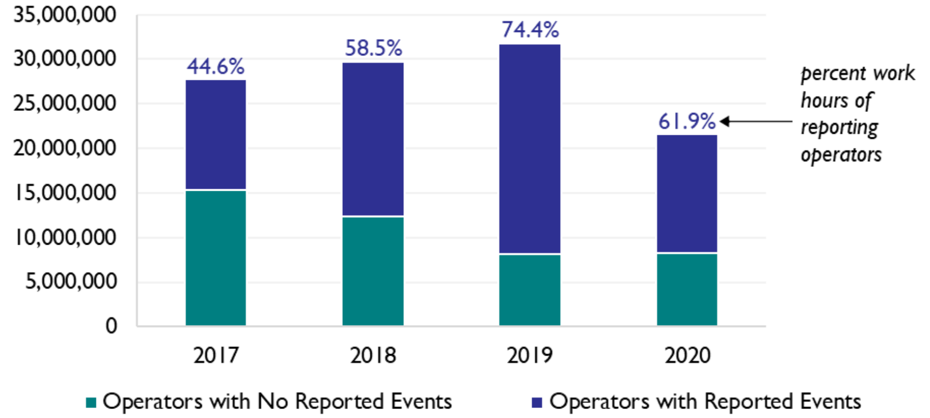
The West Texas Intermediate (WTI) crude oil price dropped to less than 17 dollars per barrel (average) in April 2020. Production from the GOM also shows a dramatic decrease beginning in May 2020, aligning with the oil price trend. Monthly oil, gas, and water volumes produced in the GOM are shown as trend lines in Figure 2. The shaded area in the same figure indicates the number of wells that were producing each month. In May 2020, the number of producing wells fell 48.9 percent from the prior month and 52.2 percent below the average number of producing wells in the first quarter of 2020. The number of shut-in wells increased from 2,840 in April to 4,081 in May, many of which (909) cited "no

Figure 2: GOM Production, 2018-2020



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

Figure 3: GOM Production Hours Worked, 2017-2020



NOTE: Includes both operator and contractor work hours. Reporting operators are those that submitted at least one event notification to SafeOCS.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program. Work hours from BSEE OCS Performance Measures data.

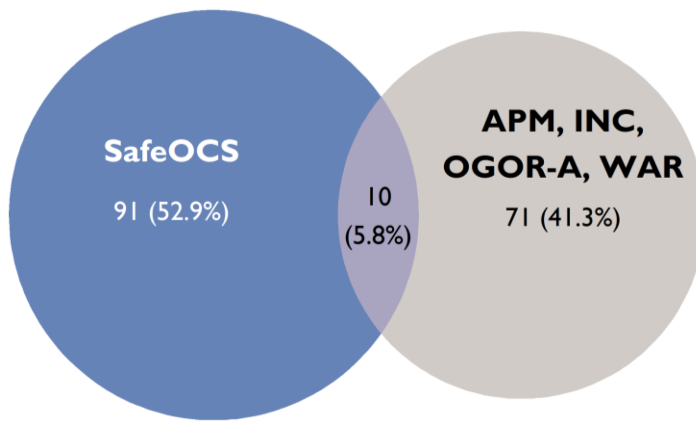
[17] U.S. Department of Transportation, Bureau of Transportation Statistics, *Transportation Statistics Annual Report 2020* (Washington, DC: 2020). https://doi.org/10.21949/1520449

pipeline—no market" as the reason the well was not producing. Consequently, from April to May, oil production fell 13.7 percent, gas production fell 19.7 percent, and water production fell 44.4 percent. As of the end of 2020, the number of producing wells still had not returned to pre-COVID levels.

Production hours worked in the GOM OCS also declined in 2020, dropping 32.3 percent from 2019 to 2020 (31.8 million to 21.6 million), as shown in Figure 3. Operators who reported SPPE failure events to SafeOCS contributed 61.9 percent of all production hours worked in 2020.

Completeness of Failure Event Reporting

Figure 4: Sources of SPPE Failure Records, 2020



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

As mentioned above, the 2020 analyses reconcile the SPPE data reported to SafeOCS using APM, INC, OGOR-A, and WAR data. The use of these additional data sources resulted in a larger set of records for failure events that occurred in the GOM OCS during 2020 operations. A review of all the available data found 172 distinct SPPE failures in 2020. Figure 4 shows the overlaps between the data sources. Of the 172 failures, 91 were reported to SafeOCS only, 71 were not reported to SafeOCS, and 10 were both reported to SafeOCS and found in the APM, INC, OGOR-A, or WAR data. Over a third (71 of 172 or 41.3 percent) of known SPPE failures events were not reported to SafeOCS. Therefore, reporting of SPPE failures to SafeOCS appears to be incomplete. The findings for each of the additional data sources are described in more detail below.

WAR Data

Analysis of the WAR data indicates that 10 SCSSV failures and five SSV failures were reported in WARs during 2020. One of the failures was also reported to SafeOCS. In five of the SCSSV failures, the tubing-retrievable SCSSV was "locked open" while a wireline-retrievable SSCSV or SCSSV was installed in the well. Of the remaining five SCSSV failures, three involved control line issues, one was a flapper failure, and one was cleared of well debris. Two of the SSV failures were also identified in the APM data, which could mean that the repairs were planned as opposed to found during well 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.

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

APM Data

Analysis of the APM data indicates that 12 SCSSV failures and three SSV failures were reported in APMs during 2020. Three of the failures were also reported to SafeOCS, and some were also reported in WAR data (eight of the SCSSV failures and two of the SSV failures, described above). The two SCSSV failures identified only in APM data involved valve replacements, and the SSV failure identified only in APM data was detected during a leak test on a well that had not produced since 2015.

INC Data

Analysis of the INC data shows that 44 SPPE failures were documented in the BSEE INC database for 2020, of which seven were reported to SafeOCS. Importantly, the number of INCs involving SPPE valves represent only those failures occurring while BSEE is visiting the platform (i.e., a subset of all failures). The failures identified in INCs include 23 SSV failures, 19 SCSSV failures, one BSDV failure, and one GLSDV failure.

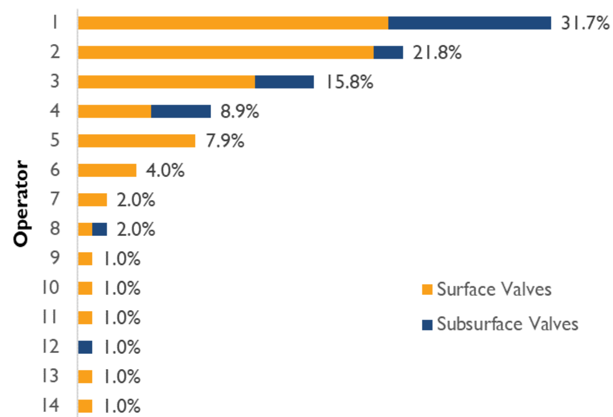
OGOR-A Data

A total of 21 SPPE failures were documented in the OGOR-A data for 2020, of which two were reported to SafeOCS. The failures identified in OGOR-A data include 13 subsurface safety valves (OGOR-A does not distinguish between SCSSVs and SSCSVs), one SCSSV (valve type determined by cross-comparison with other sources of failure records), and seven SSVs.

Who Reported Equipment Events

Figure 5 shows the percentages of 2020 SPPE reported failures by operator and the breakdown between surface and subsurface valves. The top reporting operator contributed nearly as many subsurface valve failures as all other operators combined.

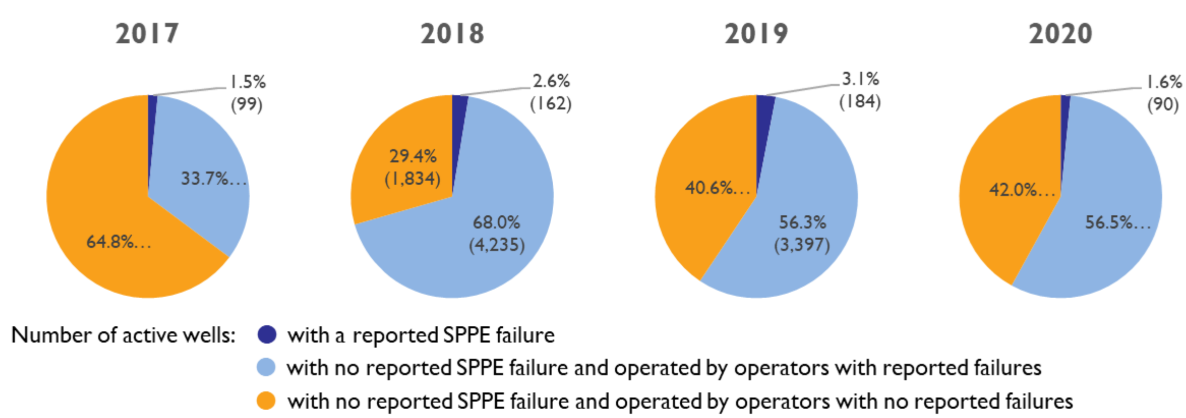
Figure 5: Reported SPPE Failure Events by Operator, 2020



NOTE: Percentage is of 101 failures reported to SafeOCS.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Figure 6 shows the distribution of active wells between operators who reported at least one failure to SafeOCS and operators with no reported failures. Each year since 2018, reporting operators were responsible for more than half of active wells. Wells with a reported SPPE failure comprised 1.6 percent of active wells in 2020, compared to 2.6 percent and 3.1 percent for 2018 and 2019, respectively.

Figure 6: Active Wells and Reporting Status of Operators, 2017-2020



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

Details of Reported Equipment

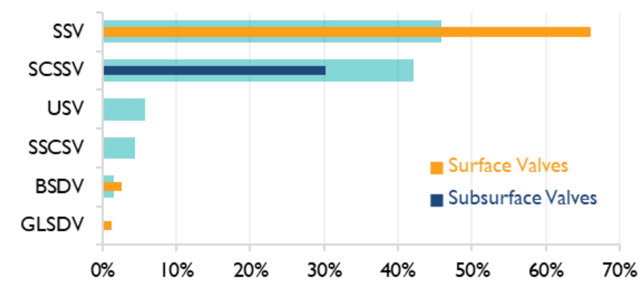
Valve Types

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.

Of the 172 failures in 2020, the specific valve type was known for 159. The remaining 13—identified in OGOR-A data—are classified as subsurface safety valves without distinguishing SCSSVs from SSCSVs. Figure 7 shows the distributions of the GOM valve population and the failures by valve type, excluding the 13 subsurface safety valve failures identified in OGOR-A data. SSVs and SCSSVs had the highest proportions of both the SPPE population and failures, collectively comprising 87.9 percent of the population and 96.2 percent of failures with known valve type in 2020. No USV or SSCSV failures were reported among the failures with known valve type. 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. Testing frequency is further considered in the discussion of SPPE failure rates below.

Figure 7: Reported SPPE Events by Valve Type, 2020



	GLSDV	BSDV	SSCSV	USV	SCSSV	SSV
Percent of Population	0.2%	1.5%	4.5%	5.8%	42.0%	45.9%
Percent of Failures	1.3%	2.5%	0.0%	0.0%	30.2%	66.0%

NOTE: Includes 159 total failures. Excludes 13 failures of subsurface safety valves identified in OGOR-A data where it could not be confirmed whether they were SCSSVs or SSCSVs.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Valve Failure Rates

In 2020, approximately 11,690 SPPE valves were in service in the GOM OCS. Because required testing frequencies vary between valve types (i.e., valves may have a monthly, quarterly, semiannual, or annual testing frequency), the methodology for calculating failure rates considers the required testing frequency for each valve type. These adjustments reduce the potential for ascertainment bias, which can occur when some valve types in the SPPE population are evaluated for potential failure more often than others.

Table 3 shows the SPPE failure rates based on the total population of each valve type and its testing frequency. The failure rate for each valve type is calculated as the number of reported failures divided by an exposure denominator of the number of installed valves multiplied by the testing frequency. For this year's report, the methodology was revised to consider the variability in testing frequency for SSVs on non-producing wells. Per 30 CFR 250.869(b), SSVs are not required to be tested if the well is disconnected from producing facilities and blind flanged, equipped with a tubing plug, or the master valves have been locked closed. The increased number of shut-in wells likely reduced the number of SSV tests performed, lowering the potential for failure identification. To account for this, a failure rate range was calculated for SSVs: the lower exposure denominator represents monthly testing for producing wells and annual testing for non-producing wells (annual testing is assumed for non-producing wells due to uncertainty in SSV testing frequency for these wells), and the higher exposure denominator value

Table 3: SPPE Failure Rates in the Gulf of Mexico, 2019-2020

		Surface Valves			Subsurface Valves			
		SSV	**BSDV**	**GLSDV**	**SCSSV**	**SSCSV**	**USV**	***Total***
Testing Frequency		1/yr. or 12/yr.	12/yr.	12/yr.	2/yr.	1 or 2/yr.	4/yr.	N/A
Reported Failures	**2019**	221 (67.2%)	8 (2.4%)	3 (0.9%)	89 (27.1%)	6 (1.8%)	2 (0.6%)	329
	2020	105 (66.0%)	4 (2.5%)	2 (1.3%)	48 (30.2%)	0 (0.0%)	0 (0.0%)	159
Installed Valves	**2019**	5,472 (46.2%)	174 (1.5%)	25 (0.2%)	4,940 (41.7%)	569 (4.8%)	667 (5.6%)	11,849
	2020	5,371 (45.9%)	178 (1.5%)	25 (0.2%)	4,914 (42.0%)	521 (4.5%)	681 (5.8%)	11,690
Exposure Denominator	**2019**	36,409 - 65,664	2,088	300	9,880	569 - 1,138	2,676	N/A
	2020	29,384 - 64,452	2,136	300	9,828	681 - 1,362	2,724	N/A
Failure Rate	**2019**	0.34% - 0.61%	0.38%	1.00%	0.90%	1.05%-0.53%	0.07%	N/A
	2020	0.16% - 0.36%	0.19%	0.67%	0.49%	0.00% - 0.00%	0.00%	N/A

NOTES:

1. Failure rate = reported failures / exposure denominator. Exposure denominator = installed valves × testing frequency.
2. SSV testing frequency: The calculation methodology considers the variability in testing frequency for SSVs on shut-in wells, for both 2019 and 2020. See report narrative for explanation.
3. Includes failures reported to SafeOCS and identified in other sources, except for subsurface safety valve failures identified only in OGOR-A data because the valve type (SCSSV or SSCSV) was not specified. Other sources include INC, WAR, and OGOR-A data for both years, and APM data for 2020, which includes three failures found only in APM data (2019 did not include a review of APM data).

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

represents maximum potential testing (every SSV tested monthly).[18] The proportion of SSVs on non-producing wells was estimated as the number of installed SSVs multiplied by the percentage of non-producing active wells.

Table 4: Chi-Square Test Comparing 2019 and 2020 Failure Rates

Failure Rate		Exposures with Failure	Exposures with No Failure	p-value
SSV Low	2019	223	65,441	p<0.001
	2020	103	64,349	
SSV High	2019	222	36,187	p<0.001
	2020	106	29,278	
SCSSV	2019	89	9,791	p<0.001
	2020	48	9,780	

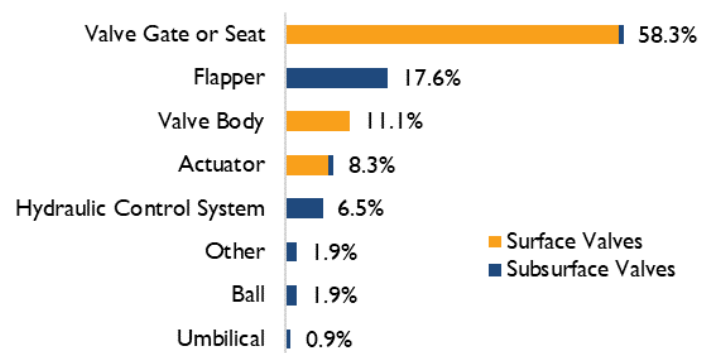
NOTE: Exposures with failure = failure rate × exposure denominator.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

As shown in Table 3, the 2020 failure rates for each SPPE valve type span from zero percent for SSCSVs and USVs, which had no reported failures, to 0.67 percent for GLSDVs. None of the failure rates among valve types exceeded 1.05 percent in either 2019 or 2020. In 2020, failure rates decreased for all valve types compared to 2019. Pearson's chi-square test was applied to assess whether changes in failure rates from 2019 to 2020 were statistically significant for valve types with at least five reported failures each year (see Table 4). Results show evidence of a statistically significant difference in failure rates between 2019 and 2020 ($p<0.001$).

Valve Components

Multiple components make up each SPPE valve.[19] In 2020, the failed component was identified for 108 failures, including 98 reported to SafeOCS and 10 identified in other sources. In total, 115 failed components were reported for the 108 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

Figure 8: Failed Components in SPPE Valves, 2020



NOTE: Percentage is of 108 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 Program.

[18] Exposure denominator calculations for SSVs:

- Lower end = (installed SSVs × percent of wells that were non-producing × 1 test) + (installed SSVs × percent of wells that were producing × 12 tests)
- Higher end = installed SSVs × 12 tests

The percent of non-producing wells in 2019 and 2020 were 48.6 percent and 59.4 percent, respectively. Well status is taken from December of each year.

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

or seat, comprising more than half (58.3 percent) of the 108 failures. These were followed by the valve body, then the actuator. 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, the failure of an actuator spring could prevent the valve from closing when called upon, possibly extending the time of the event that triggered the valve closure. Flappers and valve gates and seats, on the other hand, are internal components. Therefore, if they fail to seal, leakage would initially be contained internally. For six failures, more than one failed component was reported:

- In three cases, both the valve gate and seat and the valve body were listed.
- In one case, the valve seat and the flapper were listed.
- In one case, the actuator, control umbilical, and other (described as nitrogen-charged chambers) were listed.
- In one case, the hydraulic control system and flapper were listed.

Valve Certification

SPPE certifications fall under four types (Table 5). The Production Safety Systems Rule requires that SPPE be certified to ANSI/API Spec. Q1. BSEE may exercise its discretion to accept and approve SPPE certified under other quality assurance programs. ANSI/ASME SPPE-1 was a previous standard (1996) containing certification criteria. Although two failure reports received in 2020 reported the valve was non-certified, they were classed per API standards for a particular service, which suggests that these were reporting errors.

Table 5: Certification Status of Reported SPPE, 2020

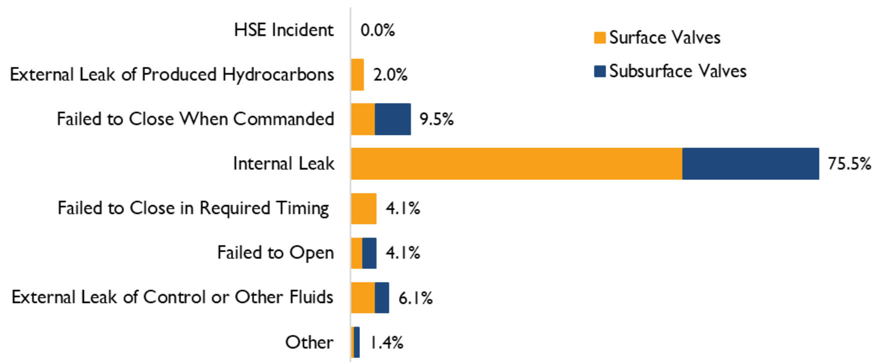
SPPE Certification	Percent of Reports
Newly installed certified SPPE pursuant to ANSI/API Spec. Q1	16.8%
Newly installed certified SPPE pursuant to another quality assurance program	1.0%
Previously certified under ANSI/ASME SPPE-1	71.3%
Non-certified SPPE	2.0%
Not answered	8.9%

NOTE: Includes 101 failures reported to SafeOCS. Excludes failures found only in other sources.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Failures and Potential Consequences

To put SPPE failures in perspective, it is helpful to consider the potential consequences of such failures based on the extent to which they degrade the installed well safety systems and potential consequences to personnel and the environment. In 2020, the event type was identified for 147 failures, including 100 reported to SafeOCS and 47 identified in other sources. In total, 151 event types were reported for the 147 failures (more than one event type may be reported for a single failure).

Figure 9: Event Type in Order of Significance, 2020



NOTE: Percentage is of 147 failures where the event type was known to BTS. Total exceeds 100 percent because more than event type may be reported for a single failure.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Figure 9 shows the distribution of event types in 2020. Some failure types, including failure to close and external leak, were clarified as part of the 2020 reporting form enhancements. BTS evaluated all 2017-2020 failures for accuracy of failure type based on the new categories. The former category *failure to close* was separated into two types: *failure to close when commanded* and *failed to close in required timing*. Failures reported as *failure to close* were reclassified as *failed to close when commanded* by default and *failed to close in required timing* only if the failure description supported that selection. External leaks were further classified based on the fluid that leaked (produced hydrocarbons versus control or other fluids). The types of failures are described below in order of significance, based on the extent of degradation of installed well safety systems and potential consequence to personnel and the environment. The number of reported failures notated in the bullets below and in Figure 9 includes 2020 failures from all sources where the event type was known to BTS, totaling 147 events.

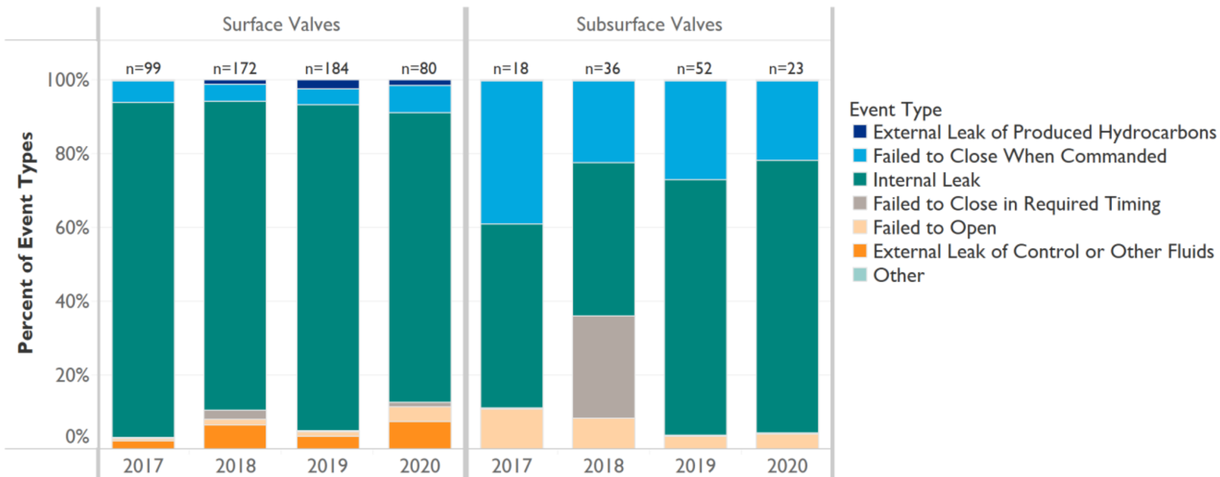
- **HSE Incident**: None of the reported failures were associated with an event that resulted in consequences to health, safety, or the environment above a specified threshold, as described in Appendix F (e.g., injury or material environmental consequence).
- **External Leak of Produced Hydrocarbons**: The most significant type of failure reported in 2020 was an external leak (i.e., loss of primary containment) where produced fluids (oil or gas) could leak into the environment. Three such failures were reported, each involving small leaks

of well fluids to the atmosphere.

- **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. Twelve such failures were reported, excluding the two listed below under failures with multiple event types.
- **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 eleven (111) such failures were reported.
- **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. Six such failures were reported.
- **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. Two such failures were reported, excluding the four listed below under failures with multiple event types.
- **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. Seven such failures were reported, excluding the two listed below under failures with multiple event types.
- **Other**: Two failures were classified as event type *other*, both of which were identified in external data sources. One described pressure build-up in the SCSSV control line, and the other described SSV corrosion.
- **Failures with Multiple Event Types**: For four failures, more than one event type was identified. In two cases, the event involved both a failure to close when commanded and a failure to open, and in another two cases, the event involved both a failure to open and an external leak of control or other fluids.

Figure 10 shows the distribution of event types each year since 2017. An 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.

Figure 10: Failure Events by Type, 2017-2020 (SafeOCS Failures Only)



NOTE: Percentage is of the number of event types reported to SafeOCS each year. Includes failures reported to SafeOCS only. More than one event type can apply to a single failure.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Well Location and Status

Shallow Water Province versus Deepwater

Many wells are located in the GOM shallow water province, which BSEE defines as the portion of the OCS with water depths of 200 meters (656 feet) or less.[20] As shown in Table 6, most active wells in 2020 (82.2 percent) were within the shallow water province, and most SPPE failures (79.0 percent) were associated with shallow water wells. Therefore, to

Table 6: Distribution of SPPE Failures by Water Depth, 2020

Water Depth (m)	SPPE Failures	Active Wells	Actual to Expected Failure Ratio
< 200 (656 ft)	132 (79.0%)	4,698 (82.2%)	0.96
200 - 800	18 (10.8%)	364 (6.4%)	1.69
> 800 (2,625 ft)	17 (10.2%)	653 (11.4%)	0.89
Total	*167*	*5,715*	*N/A*

NOTE: Excludes five failures of GLSDVs or BSDVs which can serve multiple wells producing into a common subsea flowline. Actual to expected failure ratio = percent of SPPE failures / percent of active wells.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

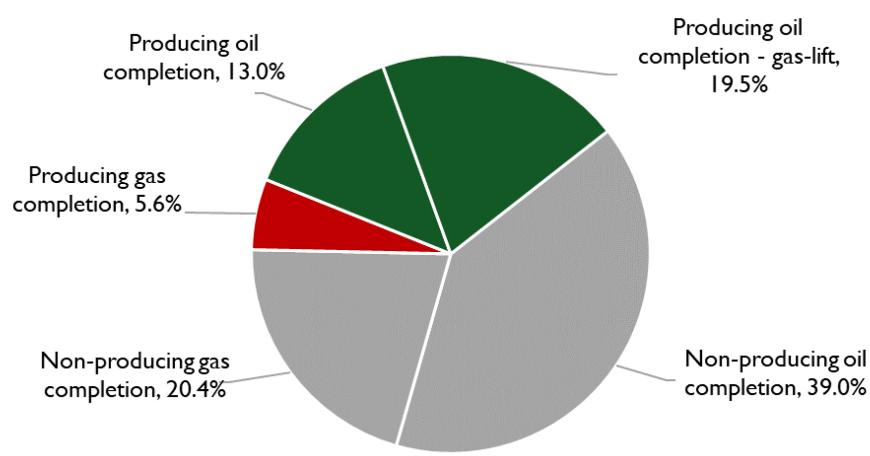
[20] Bureau of Safety and Environmental Enforcement and Bureau of Ocean Energy Management, Information/Briefing Report: Gulf of Mexico Data and Analysis/ Leasing, Drilling and Production; Gulf of Mexico Shallow Water Potential Stranded Assets, Nov. 19, 2019, https://www.bsee.gov/sites/bsee.gov/files/reports/shallow-water-report-01.pdf.

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. 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.

Well Status

The well status is an indication of the type of well and its production or injection status at the time of failure. Most active wells (97.5 percent[21]) are production wells, generally classified as producing oil or gas wells, producing oil wells with gas lift, or non-producing oil or gas wells. The remaining active wells are injection or water source wells. The well status is reported via OGOR-A forms each month, and the status may change from month to month. Figure 11 shows the percentages of the active production wells for each well status in December 2020. December was selected as a representative month for 2020 because it appears closer to a more typical month than the months following the start of the COVID-19 pandemic. The two largest wedges represent non-producing wells, comprising over half (59.4 percent) of active wells in December 2020.

Figure 11: Status of Production Wells, December 2020



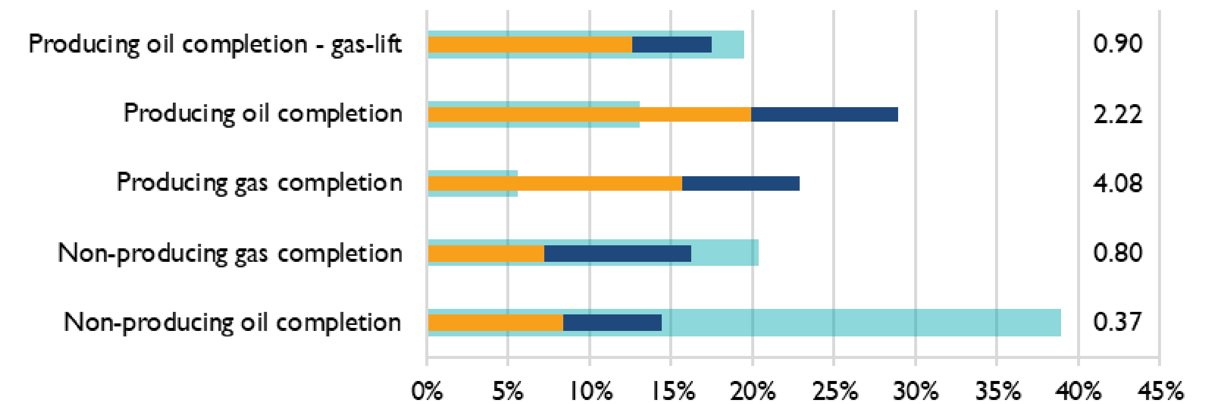
NOTE: Active wells: n=5,243. Status is taken from December 2020. Excludes 0.02 percent "producing oil completion – load oil" wells for clarity.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Figure 12 compares the status of the population of active wells to the status of 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.

[21] Calculated from December 2020 OGOR-A data.

Producing oil completions and producing gas completions show the highest percentages of failures (28.9 and 22.9 percent, respectively) and the highest failure ratios (2.22 and 4.08, respectively). About 69.3 percent of failures occurred on wells with producing status.[22]

Figure 12: Status of All Production Wells vs. Wells with SPPE Failure, 2020



	Non-producing oil completion	Non-producing gas completion	Producing gas completion	Producing oil completion	Producing oil completion - gas-lift
Active Wells	39.0%	20.4%	5.6%	13.0%	19.5%
Surface Valve Failures	8.4%	7.2%	15.7%	19.9%	12.7%
Subsurface Valve Failures	6.0%	9.0%	7.2%	9.0%	4.8%

NOTES:
1. Active wells: n=5,243. Status is taken from December 2020. Producing oil completions using load oil (0.02 percent) have been included with producing oil completions.
2. Wells with SPPE failure: n=166. Status is taken from near the time of the failure. Excludes one failure on an injection well and five failures of GLSDVs or BSDVs, which can serve multiple wells producing into a common subsea flowline. One failure on a producing oil completion using load oil was included with producing oil completions.
3. Actual to expected failure ratio = percent of SPPE failures (surface + subsurface) / percent of active wells.

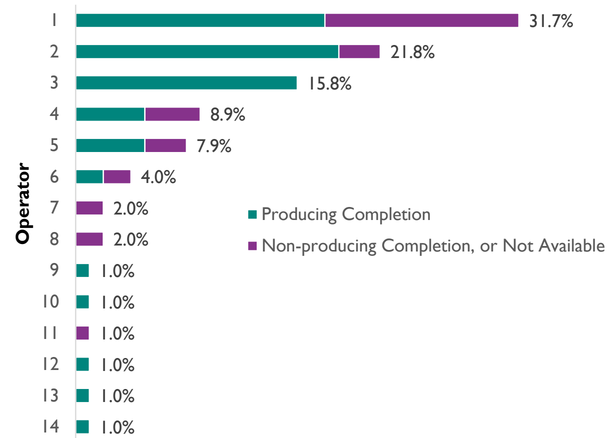
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Further analysis was conducted of the 51 failures in 2020 that occurred on wells in non-producing status. Twelve wells had produced within 60 days prior to the failure, and 39 had not. The failures on the wells with no production were almost evenly split between surface valves (19 of 39) and subsurface valves (20 of 39). In 34 of the 39 failures, there was no production in the prior month, the month of the failure, or the month after the failure. Many of the non-producing wells that experienced a failure had not produced for an extended time, as 30.8 percent (12 of 39) had no reported well test since prior to 2019. In addition, 64.1 percent of the wells (25 of 39) produced <100 bopd in their last well test, which could mean that the wells are uneconomic to produce.

[22] Percent is of 166 failures. See footnote 2 of Figure 12.

Figure 13 shows the well status of failures reported to SafeOCS for each operator. On average, operators reported more failures on producing wells (69.3 percent) than non-producing ones. For the top three reporting operators, over three-quarters of reported failures (75.7 percent) were on producing wells.

Figure 13: Reported SPPE Failure Events by Operator and Well Status, 2020



NOTE: Percentage is of 101 failures reported to SafeOCS. The well status was not available for failures of GLSDVs or BSDVs which can serve multiple wells producing into a common subsea flowline.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

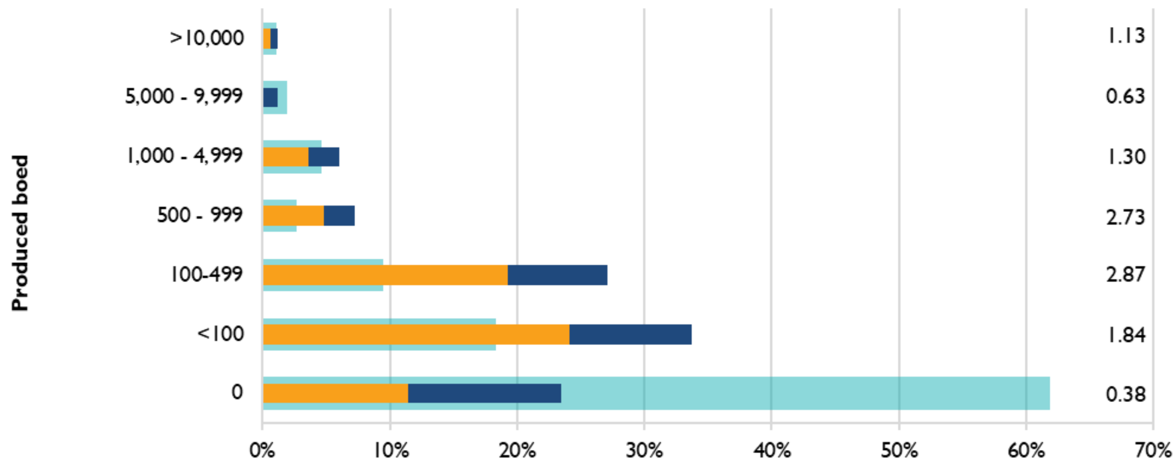
Well Fluid Rates

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 because the potential rate of the released volume is higher for wells with higher rates.

Figure 14 compares the SPPE failures grouped by well rate range with the well rates of active wells in the GOM OCS during the representative month of December 2020. Most of the failures (84.2 percent) were associated with wells that produce less than 500 boed, with more than half (57.1 percent) producing less than 100 boed. These wells pose a lower risk than higher-producing wells. About 2.4 percent of the reported failures were associated with wells producing more than 5,000 boed.

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. Wells that produced less than 100, 100-499, or 500-999 boed had the highest actual to expected failure ratios, which was also the case in 2019. In general, more failures occurred on wells with lower production rates relative to other groups.

Figure 14: Well Rates for All Wells vs. Wells with SPPE Failure, 2020



	0	<100	100-499	500 - 999	1,000 - 4,999	5,000 - 9,999	>10,000
Well Population	61.9%	18.4%	9.4%	2.7%	4.6%	1.9%	1.1%
Surface Valve Failures	11.4%	24.1%	19.3%	4.8%	3.6%	0.0%	0.6%
Subsurface Valve Failures	12.0%	9.6%	7.8%	2.4%	2.4%	1.2%	0.6%

NOTES:

1. Active wells: n=5,243. Rate is taken from December 2020.
2. Wells with SPPE failure: n=166. Rate is taken from near the time of the failure. Excludes one failure on an injection well and five failures of GLSDVs or BSDVs, which can serve multiple wells producing into a common subsea flowline.
3. Actual to expected failure ratio = percent of SPPE failures (surface + subsurface) / percent of active wells.

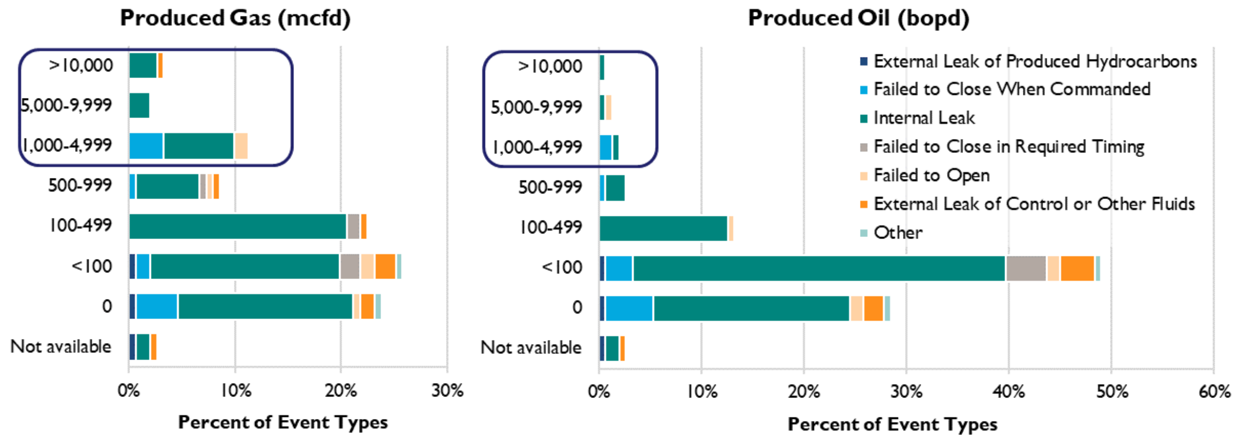
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

The average daily production rates shown in Table 2 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 2020 was 72,146 boed. Comparing this figure to the average daily production from the GOM OCS in 2020 (2,414,434 boed) indicates that only 3.0 percent of the GOM OCS production could have been directly affected by the 101 reported SPPE failures. Considering failures identified in all data sources (SafeOCS, APM, INC, OGOR-A, and WAR data), the average daily production volume from wells with an SPPE failure in 2020 increases to 86,136 boed, representing 3.6 percent of GOM OCS production. This percentage could be underestimated due to a small number of failures lacking production information.

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 15 shows the distribution of failures by well rate, with failure type indicated by color.

Figure 15: Type of Reported Failures by Well Rate, 2020



NOTE: Percentage is of 151 event types. In 2020, 151 event types were reported for 147 failures (more than one event type can apply to a single failure), and the event type was unknown to BTS for the remaining failures. The well rates were not available for failures of GLSDVs or BSDVs, which can serve multiple wells producing into a common subsea flowline.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

As shown in Figure 15, the most significant event type among higher-producing wells (greater than 1,000 bopd or mcfd) in 2020 was a failure to close when commanded, totaling five events:

- All five events occurred on wells with higher gas rates (1,000-4,999 mcfd), and two events occurred on wells that also had higher oil rates (1,000-4,999 bopd).
- Four events were failures of tubing-retrievable SCSSVs, three of which were on subsea wells and were designed for higher pressures or temperatures (>15,000 psi or >350 F). The installation date was reported for one of the SCSSVs (2014). The flapper failed in two of the SCSSV failures, and the other two were hydraulic control system failures. One of the flapper failures also mentioned wellbore debris as a contributing factor.
- One of the SCSSV failures was a repeated failure of the hydraulic control system, following a failure reported 11 months prior. In the previous failure, the valve failed to close due to a blockage in a hydraulic control line and was corrected by cycling the control lines. How the problem was corrected was not specifically reported for the more recent failure; however, the well was able to restart production.
- The fifth event was an SSV gate/seat failure on a producing gas well. Valve seat degradation contributed to the failure, and the reported root cause was wear and tear (no installation date was reported).
- Four of the five failures were detected during leakage tests, and one (an SCSSV failure) was detected after bringing the well back online following a shut-in for storm evacuation.

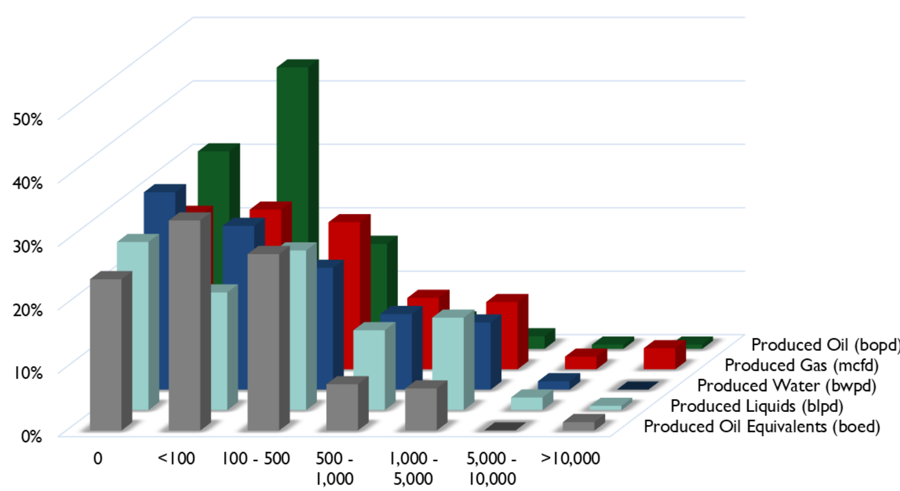
The three events involving external leaks of produced hydrocarbons occurred on a non-producing well, a well producing <100 bopd and mcfd, and a well for which the well rate information was not available. The three events comprised:

- An external leak of an SSV actuator was seen by an operator bringing a well on line. The well was producing at less than 100 bopd and less than 100 mcfd. This was a repeated failure, and it was addressed by replacing the valve bonnet packing a second time after nine months,
- An external leak of produced fluid was observed during visual inspection of an SSV for a non-producing well. No additional information was available for this failure.
- A valve packing leak associated with a BSDV was found during start up after a process upset. Well rate information was not available for the BSDV, which can serve multiple wells producing into a common subsea flowline. The corrective action for the failure was reported as replacement by a contractor on location.

Rates of Oil, Gas, and Water

Some failures (151 in 2020) 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 (for example, an external leak of control fluid) are excluded. For failures affected by produced well fluids (fluid-affected failures), different parameters related to each of the three phases of the produced fluid stream (oil, gas, and water) were evaluated. Figure 16 shows the distribution of 2020 fluid-affected failures independently for several production rate parameters.

Figure 16: Failures Grouped by Well Fluid Rate Ranges, 2020



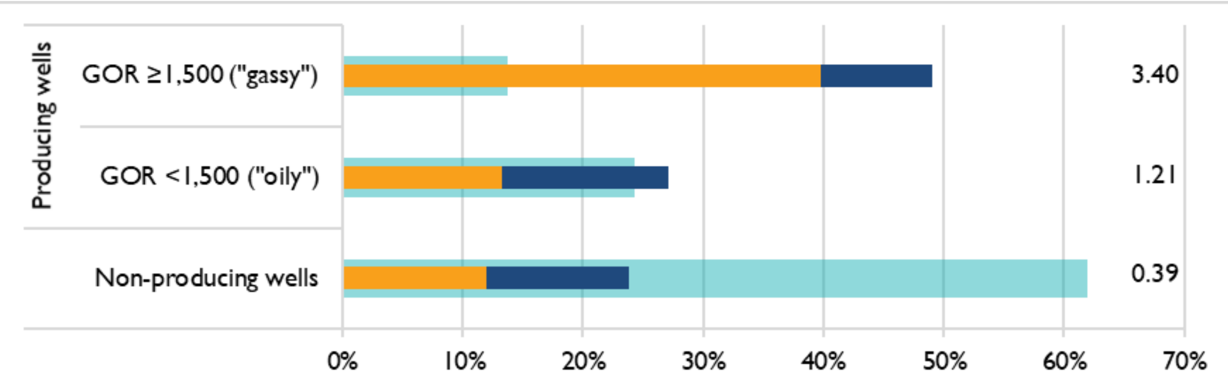
NOTE: Includes 151 total failures where produced fluids could have been a factor in the failure and well rates were available.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

For produced oil, about 44.4 percent of the failures were on wells that produced greater than 0 and less than 100 bopd, and most failures (92.1 percent) were on wells in the first three rate groups (0, <100, and 100-500 bopd). The breakdown is similar for produced gas and water, and for the two calculated parameters (produced oil equivalents and produced liquids). More failures occurred on wells in the 500-1,000 and 1,000-5,000 water and gas rate groups than in the oil rate groups of the same range.

Gas-Oil Ratio (GOR)

The fluid proportions produced from each well differ depending on the reservoir and placement of the well in that reservoir. The GOR describes the volume of gas produced from the well as compared to the volume of oil produced and can be useful in determining whether a well produces primarily gas or oil. Figure 17 shows producing wells divided into "gassy" or "oily" wells based on GOR, where gassy wells are defined for purposes of this report as those with a GOR ≥1,500 cf/bbl. 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 seen in the figure, the failure ratio for gassy wells is much higher than that of oily wells.

Figure 17: Gassy and Oily Wells Based on GOR, 2020



	Non-producing wells	Producing wells GOR <1,500 ("oily")	Producing wells GOR ≥1,500 ("gassy")
Well Population	61.9%	24.3%	13.8%
Surface Valve Failures	11.9%	13.2%	39.7%
Subsurface Valve Failures	11.9%	13.9%	9.3%

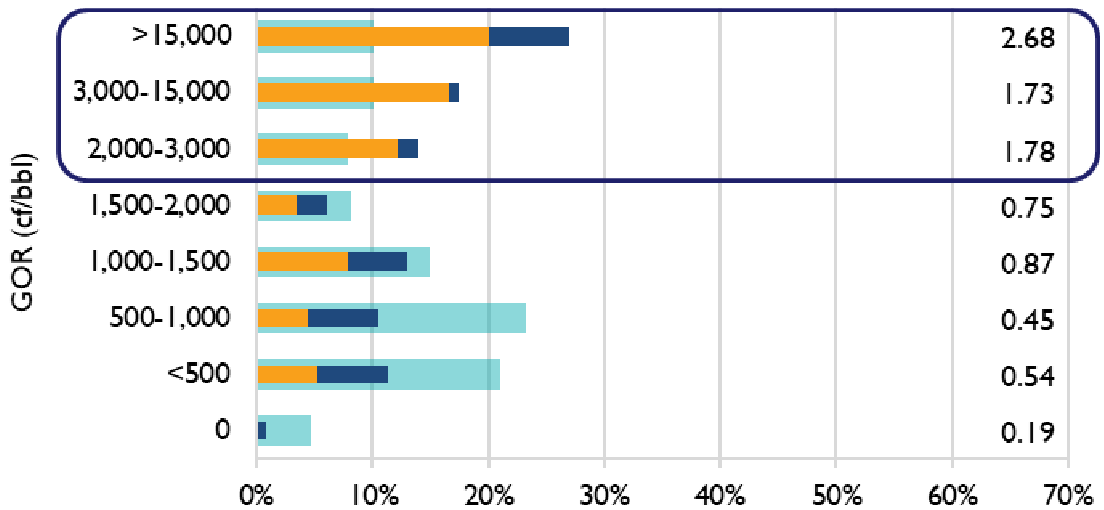
NOTES:

1. Active wells: n=5,243. Rate is taken from December 2020.
2. SPPE failures: n=151. Includes failures from producing and non-producing wells where produced fluids could have been a factor in the failure and well rates were available. Rate is taken from near the time of 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 Program.

Further breakdown of producing wells into GOR ranges in Figure 18 shows that those with the higher GOR (2,000 cf/bbl and above) experienced more failures in 2020. Wells in these groups also had higher failure ratios, shown on the right side of the chart, indicating disproportionately more failures on these wells compared to wells in other GOR groups.

Figure 18: SPPE Failures and Producing Wells by GOR Range, 2020



	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	4.7%	21.1%	23.2%	14.9%	8.2%	7.8%	10.1%	10.1%
Surface Valve Failures	0.0%	5.2%	4.3%	7.8%	3.5%	12.2%	16.5%	20.0%
Subsurface Valve Failures	0.9%	6.1%	6.1%	5.2%	2.6%	1.7%	0.9%	7.0%

NOTES:

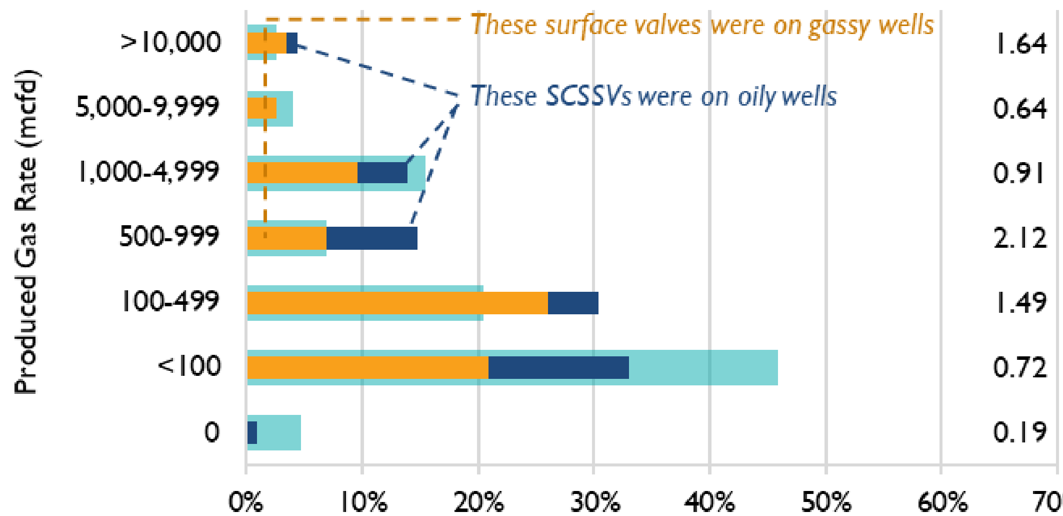
1. Active wells: n=1,997. Includes producing wells only. Rate is taken from December 2020.
2. Wells with SPPE failure: n=115. Includes failures on producing wells where produced fluids could have been a factor in the failure and well rates were available. Rate is taken from near the time of the failure.
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 Program.

Produced Gas Rate

Figure 19 shows the failures in each gas rate group as compared to the producing well population. Most of the producing well population had a gas rate between zero and 100 mcfd, and most failures occurred on wells within that same gas rate group. The 500-999 mcfd group had the highest actual to expected failure ratio (2.12), indicating that more failures occurred on wells in this group compared to other gas rate groups. Further evaluation indicated that for wells with gas rates greater than 500 mcfd, all surface valve failures were on gassy wells (GOR ≥1,500), whereas all SCSSV failures were on oily wells (GOR <1,500).

Figure 19: SPPE Failures and Active Wells by Gas Rate Group, 2020



	0	<100	100-499	500-999	1,000-4,999	5,000-9,999	>10,000
Well Population	4.7%	45.8%	20.5%	7.0%	15.4%	4.1%	2.7%
Surface Valve Failures	0.0%	20.9%	26.1%	7.0%	9.6%	2.6%	3.5%
Subsurface Valve Failures	0.9%	12.2%	4.3%	7.8%	4.3%	0.0%	0.9%

NOTES:

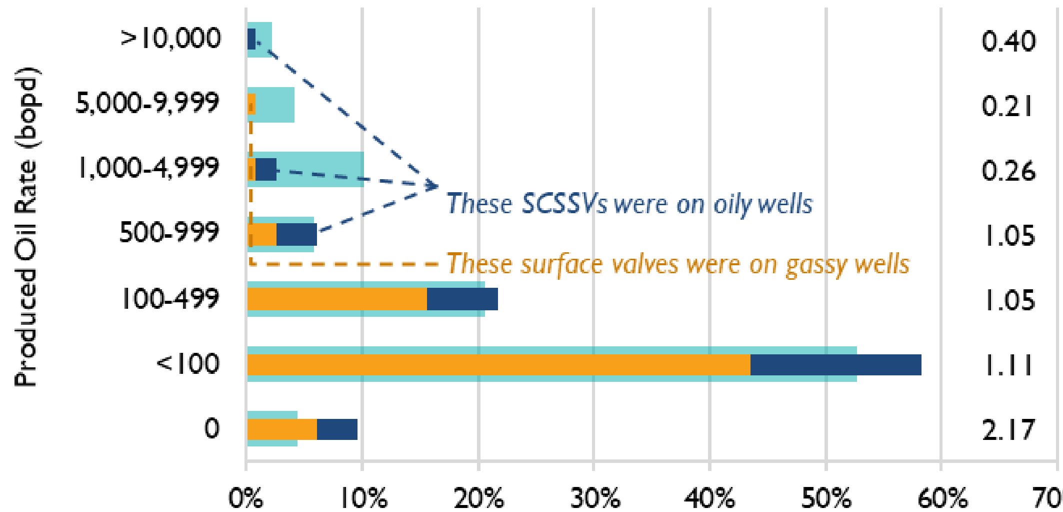
1. Active wells: n=1,997. Includes producing wells only. Rate is taken from December 2020.
2. Wells with SPPE failure: n=115. Includes failures on producing wells where produced fluids could have been a factor in the failure and well rates were available. Rate is taken from near the time of the failure.
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 Program.

Produced Oil Rate

Figure 20 shows the failures in each oil rate group as compared to the producing well population. Most of the producing well population had an oil rate between zero and 100 bopd, and most failures occurred on wells within that same oil rate group. More failures occurred on wells in the zero bopd group relative to other oil rate groups, as indicated by its higher actual to expected failure ratio. Further evaluation of the failures in the 10,000 bopd oil rate group confirmed that those few SCSSV failures were on oily wells (GOR <1,500). For wells with an oil rate greater than 500 bopd, all surface valve failures were on gassy wells (GOR ≥1,500), whereas all subsurface valve failures were oily wells (GOR <1,500).

Figure 20: SPPE Failures and Active Wells by Oil Rate Group, 2020



	0	<100	100-499	500-999	1,000-4,999	5,000-9,999	>10,000
Well Population	4.4%	52.6%	20.6%	5.8%	10.2%	4.2%	2.2%
Surface Valve Failures	6.1%	43.5%	15.7%	2.6%	0.9%	0.9%	0.0%
Subsurface Valve Failures	3.5%	14.8%	6.1%	3.5%	1.7%	0.0%	0.9%

NOTES:

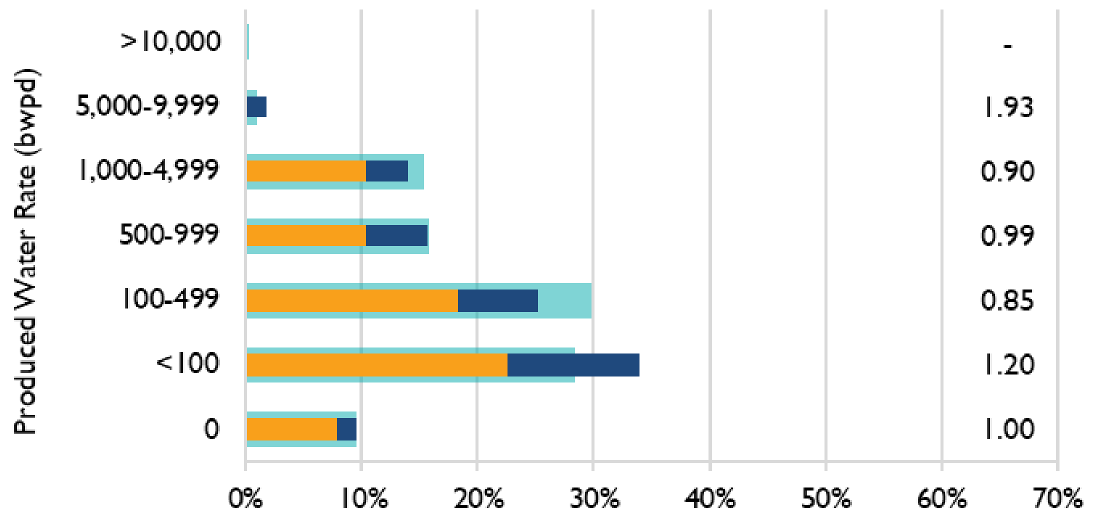
1. Active wells: n=1,997. Includes producing wells only. Rate is taken from December 2020.
2. Wells with SPPE failure: n=115. Includes failures on producing wells where produced fluids could have been a factor in the failure and well rates were available. Rate is taken from near the time of the failure.
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 Program.

Produced Water Rate

Figure 21 shows the failures in each water rate group as compared to the producing well population. Most of the producing well population (58.1 percent) had a water rate between 0 and 500 bwpd, and most failures (59.2 percent) occurred on wells in these groups. More failures occurred on wells in the 5,000-9,999 bwpd group relative to other water rate groups (actual to expected failure ratio = 1.93); however, this figure is based on small counts for this group. Each of the two failures in this group were on oily wells (GOR <1,500).

Figure 21: SPPE Failures and Active Wells by Water Rate Group, 2020



	0	<100	100-499	500-999	1,000-4,999	5,000-9,999	>10,000
Well Population	9.6%	28.3%	29.8%	15.8%	15.4%	0.9%	0.2%
Surface Valve Failures	7.8%	22.6%	18.3%	10.4%	10.4%	0.0%	0.0%
Subsurface Valve Failures	1.7%	11.3%	7.0%	5.2%	3.5%	1.7%	0.0%

NOTES:

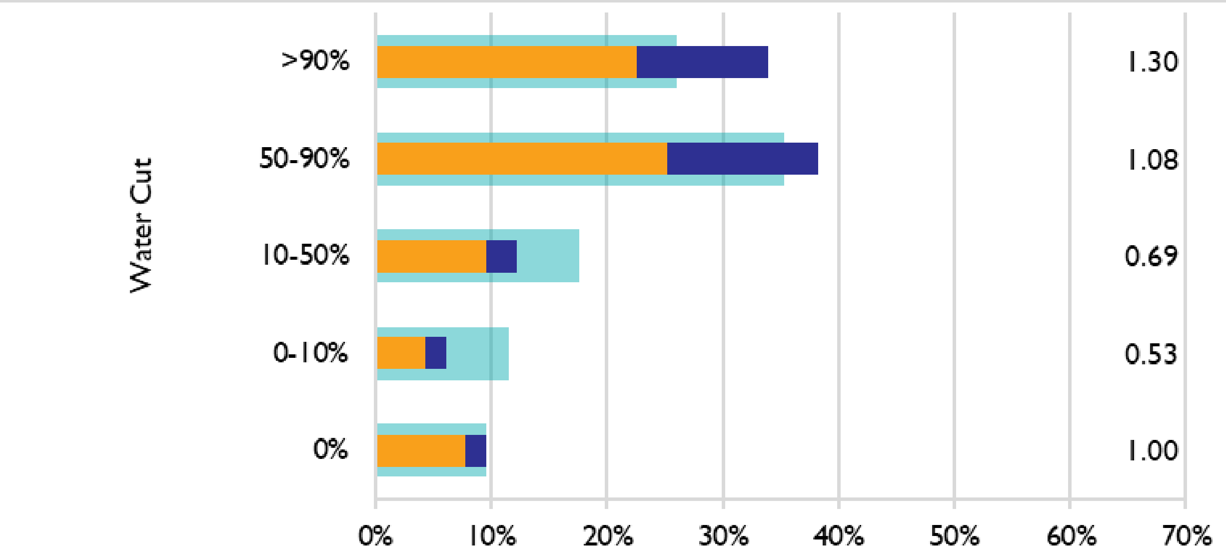
1. Active wells: n=1,997. Includes producing wells only. Rate is taken from December 2020.
2. Wells with SPPE failure: n=115. Includes failures on producing wells where produced fluids could have been a factor in the failure and well rates were available. Rate is taken from near the time of the failure.
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 Program.

Water Cut Range

A well's water cut is its ratio of produced water to total produced liquids (oil plus water). Figure 22 shows the failures in each water cut group as compared to the producing well population. The higher failure ratios are in the two highest water cut groups, 50-90 percent and >90 percent, but the ratios are only slightly greater than one. High water cut wells typically produce more sand than wells with low water cut due to pressure drops associated with water moving through the reservoir formation. This characteristic could result in more sand flowing through the SPPE valves (SSVs and SCSSVs), which can be erosive and cause premature valve failure. Sand was reported for five of 44 failures (11.4 percent) in the 50-90 percent water cut group and one failure in the >90 percent group. This topic is addressed further in the discussion of contaminants below.

Figure 22: SPPE Failures and Active Wells by Water Cut Range, 2020



	0%	0-10%	10-50%	50-90%	>90%
Well Population	9.6%	11.6%	17.6%	35.3%	26.0%
Surface Valve Failures	8%	4%	10%	25%	23%
Subsurface Valve Failures	2%	2%	3%	13%	11%

NOTES:

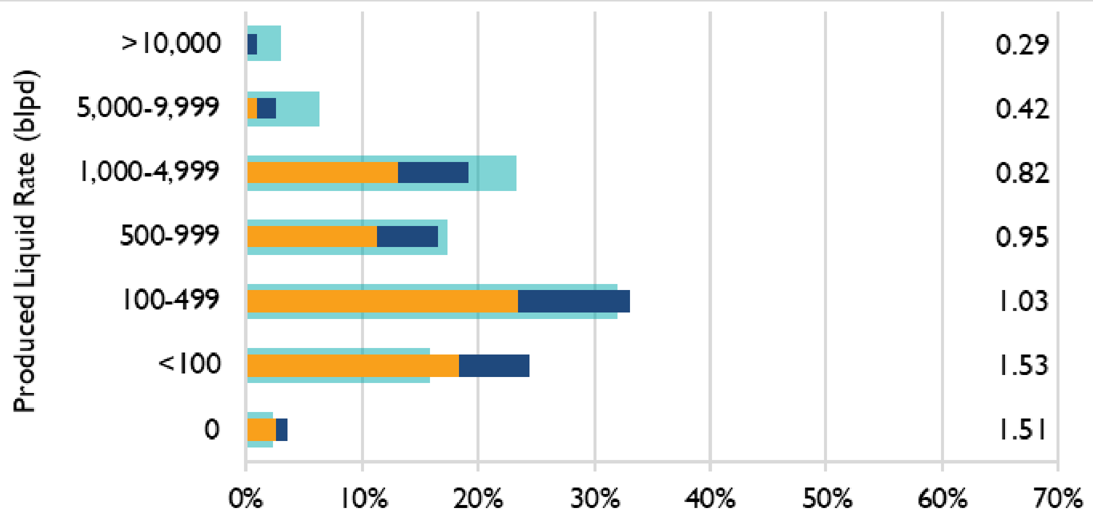
1. Active wells: n=1,997. Includes producing wells only. Rate is taken from December 2020.
2. Wells with SPPE failure: n=115. Includes failures on producing wells where produced fluids could have been a factor in the failure and well rates were available. Rate is taken from near the time of the failure.
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 Program.

Total Liquid Rate

The total liquid rate (i.e., produced liquid rate) is calculated as the sum of the oil rate and the water rate. Figure 23 shows the failures in each liquid rate group as compared to the producing well population. The 0 and 0-100 blpd groups had the highest actual to expected failure ratios (1.51 and 1.53), driven by higher failure ratios in the corresponding oil and water rate groups. Further evaluation of the failures in these groups showed they were primarily on gassy wells (GOR ≥1,500).

Figure 23: SPPE Failures and Active Wells by Total Liquid Rate, 2020



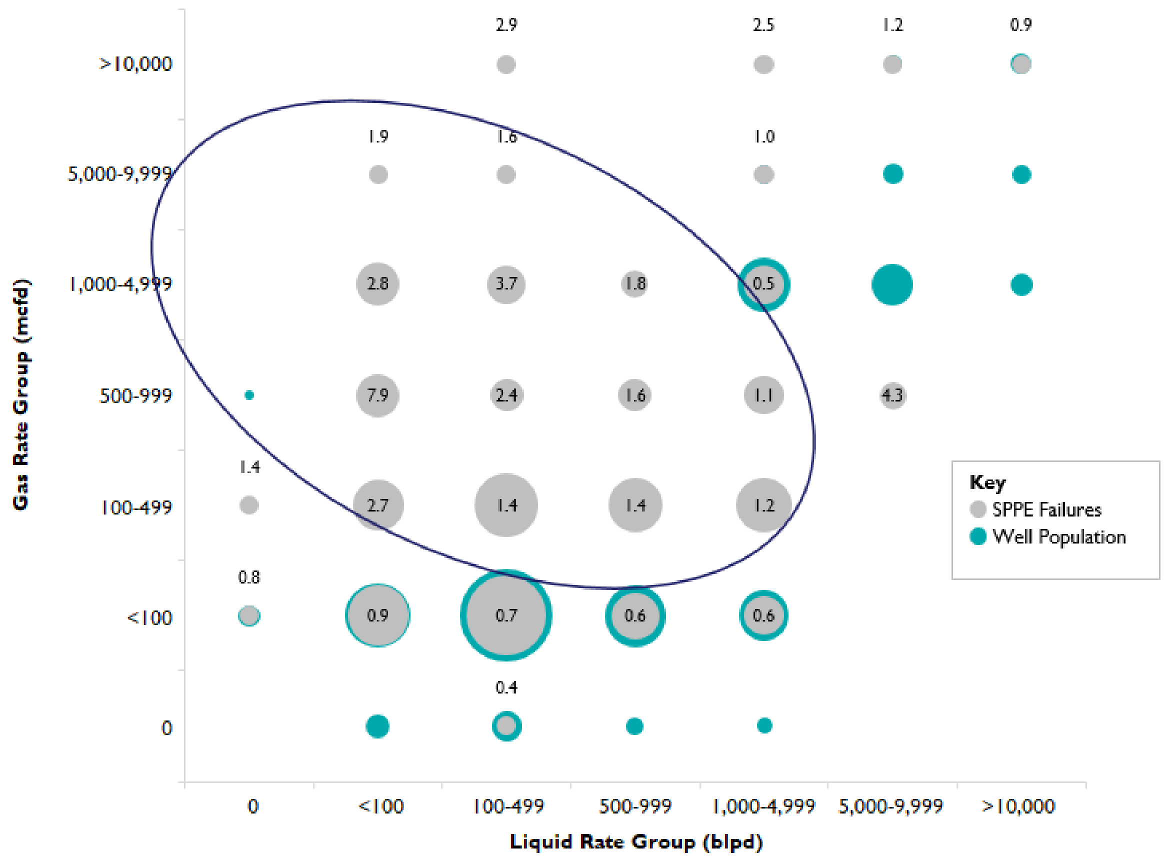
	0	<100	100-499	500-999	1,000-4,999	5,000-9,999	>10,000
Well Population	2.3%	15.9%	32.0%	17.3%	23.2%	6.3%	3.0%
Surface Valve Failures	2.6%	18.3%	23.5%	11.3%	13.0%	0.9%	0.0%
Subsurface Valve Failures	0.9%	6.1%	9.6%	5.2%	6.1%	1.7%	0.9%

NOTES:
1. Active wells: n=1,997. Includes producing wells only. Rate is taken from December 2020.
2. Wells with SPPE failure: n=115. Includes failures on producing wells where produced fluids could have been a factor in the failure and well rates were available. Rate is taken from near the time of 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 Program.

Recalling from Figure 18 that the higher GOR groups experienced higher failure ratios, and considering that the wells with lower total liquid rates had higher failure ratios, BTS further explored the combination of these parameters. In Figure 24, the total liquid rate group is plotted against the gas rate group for the failures and the producing well population, with bubble size representing the percent of the distribution. The failure bubble (gray) is positioned on top of the population bubble (teal), so bubbles with no teal showing indicate a high number of failures relative to other bubbles. In nearly all cases where the gas rate is greater than 100 mcfd, except those of very high liquid rate combined with high gas rate, the failure ratio is greater than one.

Figure 24: Gas Rate versus Liquid Rate, 2020



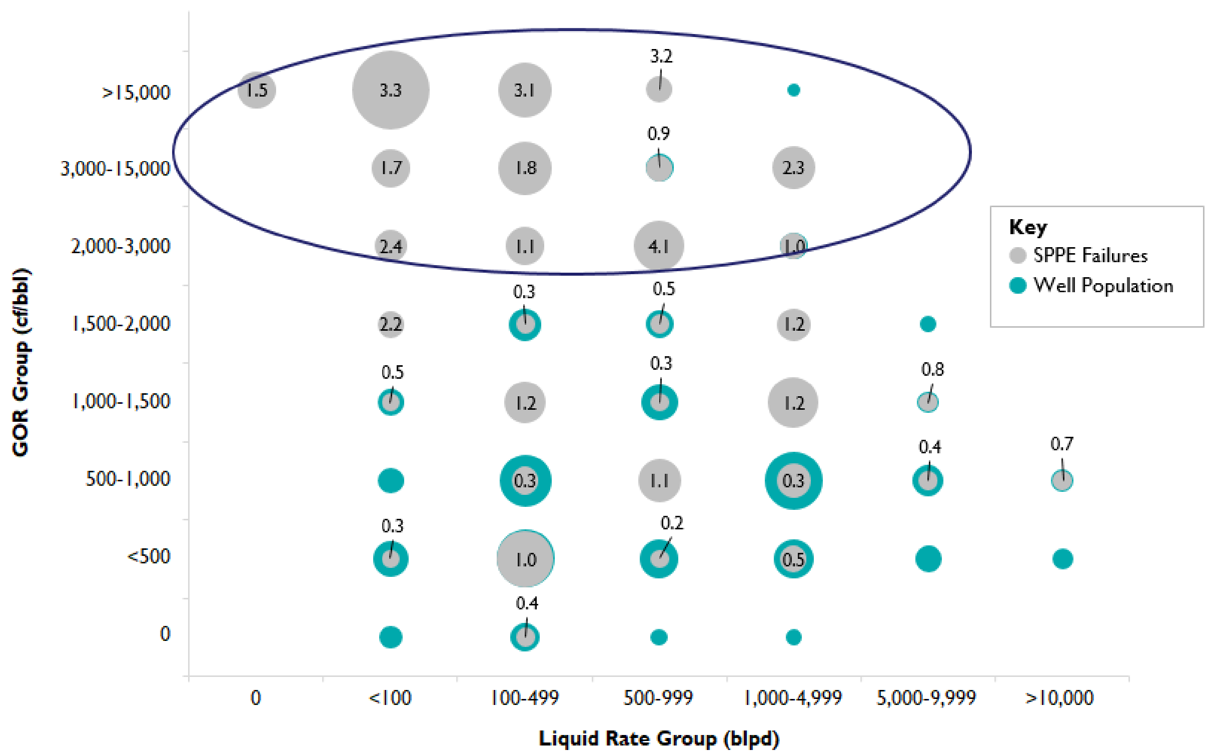
NOTES:

1. Bubble size represents the relative distribution of the well population or wells with SPPE failures.
2. To preserve confidentiality, neither wells nor failures are shown for groups that represent fewer than five operators.
3. Active wells: n=1,997. Includes producing wells only. Rates are taken from December 2020.
4. Wells with SPPE failure: n=115. Includes failures on producing wells where produced fluids could have been a factor in the failure and well rates were available. Rate is taken from near the time of the failure.
5. Data labels are the 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 Program.

Plotting the GOR group against the total liquid rate group (Figure 25) indicates that the higher GOR groups have the higher failure ratios regardless of total liquid rate. BTS will continue to build on these analyses to better understand the relationships between well rates and likelihood of SPPE failure.

Figure 25: GOR versus Liquid Rate, 2020



NOTES:

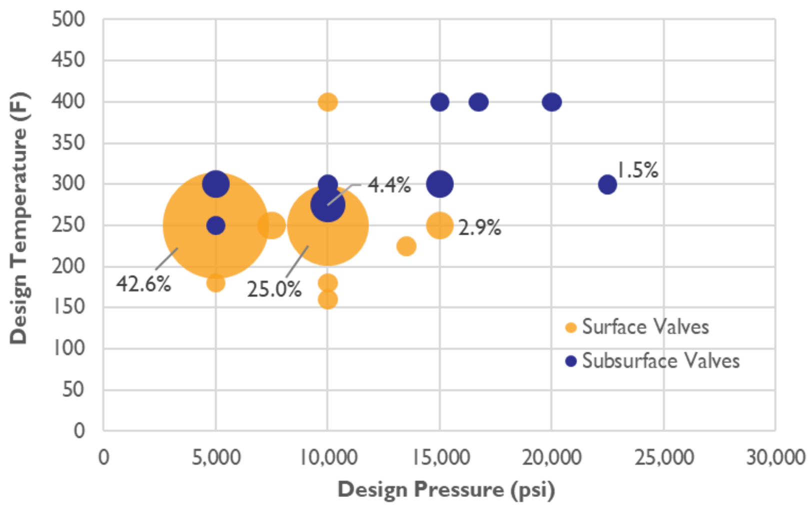
1. Bubble size represents the relative distribution of the well population or wells with SPPE failures.
2. To preserve confidentiality, neither wells nor failures are shown for groups that represent fewer than five operators.
3. Active wells: n=1,997. Includes producing wells only. Rates are taken from December 2020.
4. Wells with SPPE failure: n=115. Includes failures on producing wells where produced fluids could have been a factor in the failure and well rates were available. Rate is taken from near the time of the failure.
5. Data labels are the 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 Program.

SPPE Pressure and Temperature Rating

Figure 26 shows the pressure and temperature ratings for 68 failures in 2020 with available data. Thirteen events 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). Ten of these are shown in the chart while three are omitted because the design temperature was not reported.[23] No 2020 events reported operating a valve in conditions out of its specified pressure or temperature range as a contributing factor to the failure.

Figure 26: Percent of Failures by Valve Pressure and Temperature Ratings, 2020



NOTE: Percentage is of 68 failures where both the pressure rating and the temperature rating of the valve were known to BTS.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

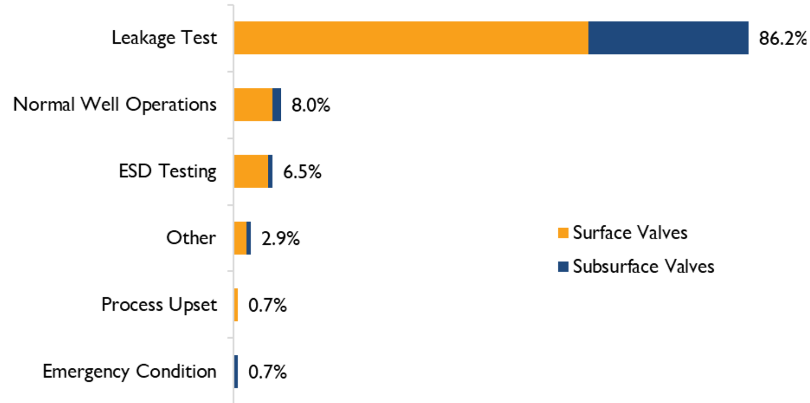
How Failures Were Detected

SPPE failures can occur when the valve is automatically or manually called to close via the control system. They can be detected in several ways, such as during testing, while the equipment is in normal operation, or when production halts (is shut-in) due to abnormal or emergency conditions. In 2020, information on the detection method was available for 138 failures, including 99 reported to SafeOCS and 39 identified in other sources. In total, 145 detection methods were reported for the 138 failures (more than one detection method may be reported for a single failure). Most of those reported failures

[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.

(86.2 percent) were found during routine leakage tests (see Figure 27). One failure (0.7 percent) was reported as detected through an emergency condition, where an SCSSV failed to close following its shut-in for storm evacuation. One failure (0.7 percent) was detected through a process upset, but no description of the process upset was provided. For seven failures, more than one detection method was reported. In three cases, both leak testing and ESD testing were listed, and in four cases, both leak testing and normal well operations were listed.

Figure 27: Failure Detection Methods, 2020

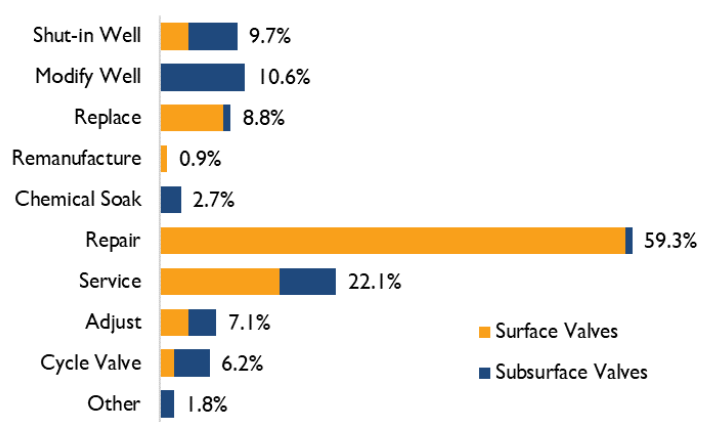


KEY: ESD—emergency shutdown.
NOTE: Percentage is of 138 failures where the detection method was known to BTS. Total exceeds 100 percent because more than one detection method may be reported for a single event.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

How Failures Were Addressed

In 2020, corrective actions were identified for 113 failures, including 94 failures reported to SafeOCS and 19 identified in other sources. In total, 143 corrective actions were reported for the 113 failures (more than one corrective action may be reported for a single failure). Figure 28 shows the distribution of corrective actions, which range from component servicing to repair or replacement. A repair was the most common corrective action, reported for 59.3 percent of the 113 events.

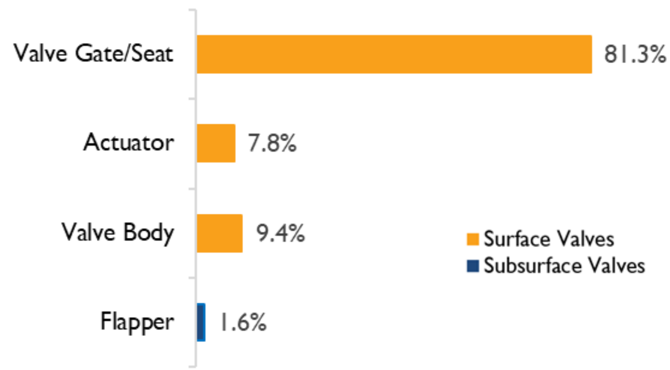
Figure 28: Reported Corrective Actions, 2020



NOTE: Percentage is of 113 failures where the corrective action was known to BTS. Total exceeds 100 percent because more than one corrective action may be reported for a single event. Corrective actions are listed from higher to lower degree of intervention.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Repair events were further classified based on the type of component repaired (Figure 29) to gain more insight into the corrective action taken. As expected, based on reported component failures, the most often repaired component was the valve gate or seat, which comprised 81.3 percent of repairs.

Figure 29: SPPE Components Repaired, 2020



NOTE: Percentage is of 64 repaired components.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

For 28 failures, multiple corrective actions were taken to address the issue, e.g., testing to locate the failed valve, inspecting the valve to pinpoint the issue, servicing the valve, and retesting. In six cases, well shut-in was reported as a corrective action with one or two additional corrective actions, such as modify well or repair; in 20 cases, servicing the valve was reported with at least one other corrective action; and in two cases, adjusting the valve was reported with either repair or replacement.

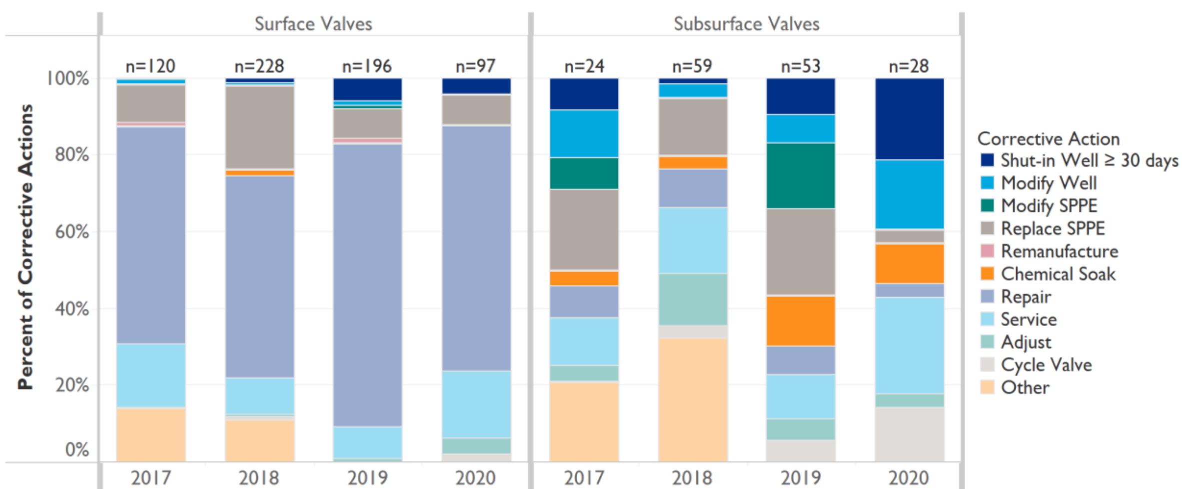
The same types of corrective actions were sometimes reported differently. For example, a repair may have been reported as *repair*, *replace* (often when only part of the valve was replaced), or in some cases another action such as *overhaul* or *service*. Failure reports were qualitatively analyzed to determine corrective actions, applying the following definitions, which were included in the reporting form revision.

- *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.
- *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.

Figure 30 shows the distribution of corrective actions each year since 2017. While most surface valves were corrected by repair, corrective actions were more varied for subsurface valves.

Figure 30: Reported Corrective Actions, 2017-2020 (SafeOCS Failures Only)



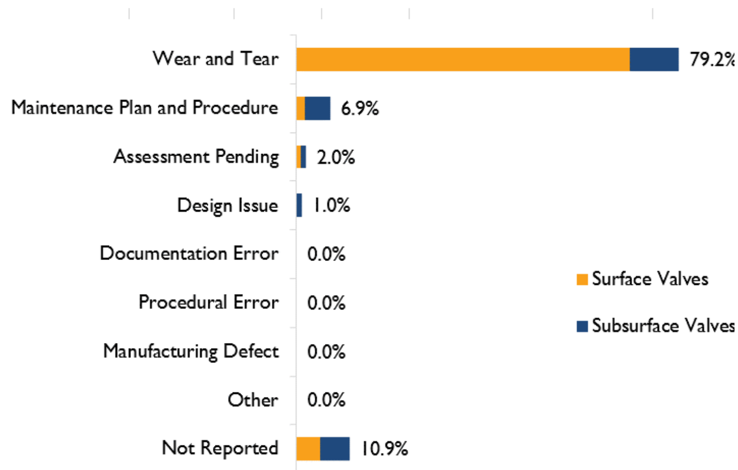
NOTE: Percentage is of the number of corrective actions reported to SafeOCS each year. Includes failures reported to SafeOCS only. Corrective actions were not reported for all failures, and more than one corrective action can apply to a single failure.
SOURCE: U.S. Department of Transportation, Bureau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

Root Causes and Contributing Factors of Failures

Root Causes

Figure 31 shows the reported suspected root causes of SPPE failures in 2020. Wear and tear was the most reported root cause, reported for 80 of 101 failures (79.2 percent). Surface valves make up most wear and tear failures, with 69.3 percent of surface valve failures attributed to wear and tear. Maintenance plan and procedure was reported as the root cause for seven failures (6.9 percent), six of which indicated the presence of contaminants (scale, sand, or CO_2).

Figure 31: Root Causes of Reported Failure Events, 2020



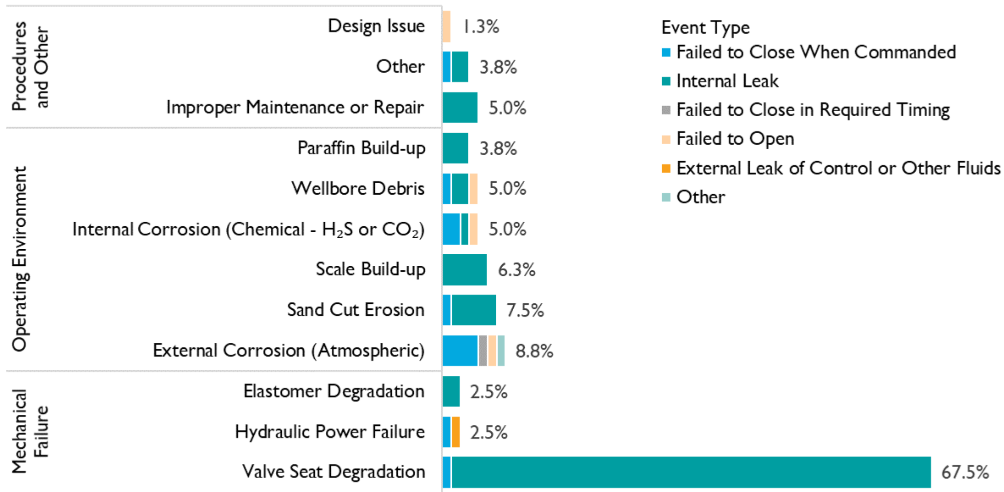
NOTE: Percentage is of 101 failures reported to SafeOCS.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

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 80 failures occurring in 2020, including 77 failures reported to SafeOCS and three identified in other sources. In total, 95 contributing factors were reported for the 80 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 32.

Valve seat degradation was the most reported contributing factor, reported for 67.5 percent of the 80 events. This is expected since valve gates or seats were the most reported failed component. Factors

Figure 32: Factors Contributing to Equipment Failures, 2020



NOTE: Percentage is of 80 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 Program.

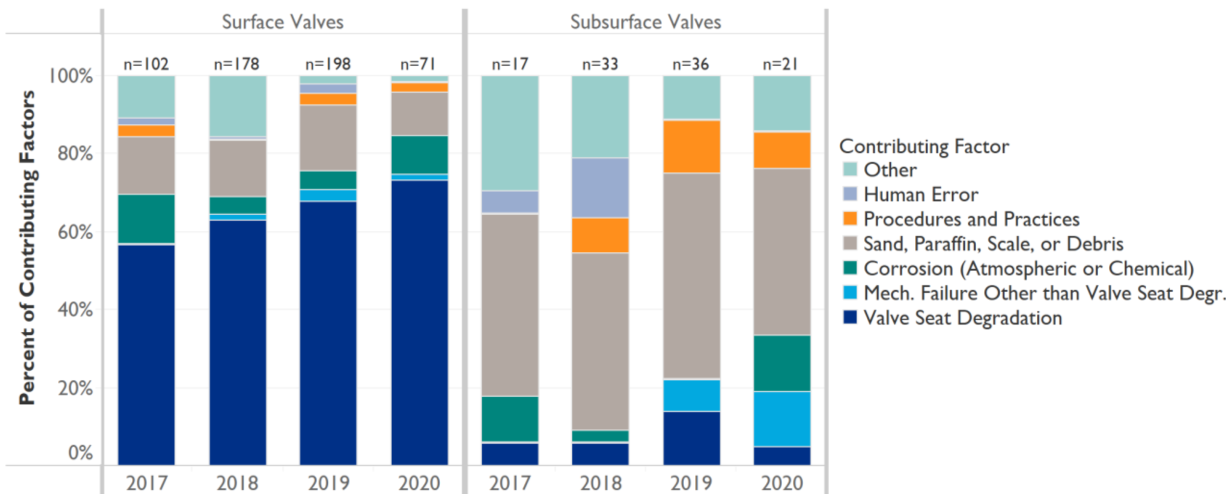
related to the operating environment—atmospheric or chemical corrosion, sand, paraffin, debris, and scale—were designated as contributing factors in 36.4 percent of the 80 failures. Among these, chemical corrosion (internal corrosion usually caused by the presence of either H_2S or CO_2) or atmospheric corrosion (external corrosion usually caused by moisture or chlorides that affect susceptible metal surfaces) were listed as a contributing factor for 13.8 percent of the 80 failures. Depending on the metallurgy, the temperature, and the concentration of H_2S or CO_2, corrosion could occur quickly or from prolonged exposure. Human error was not reported as a contributing factor for any 2020 events.

For fifteen failures, two contributing factors were reported, as noted below:

- In five cases, valve seat degradation was reported with an operating environment factor of sand cut erosion, scale, or paraffin.
- In four cases, improper maintenance was reported with the second factor of valve seat degradation, scale, or other (described as trapped gas).
- In three cases, two operating environment factors were reported.
- In one case, chemical corrosion and design issue were reported.
- In one case, scale and other (described as high water cut) were reported.
- In one case, hydraulic power failure and other (described as possible asphaltenes) were reported.

Figure 33 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.

Figure 33: Factors Contributing to Equipment Failures, 2017-2020 (SafeOCS Failures Only)



NOTE: Percentage is of the number of event types reported to SafeOCS each year. Includes failures reported to SafeOCS only. Contributing factors were not reported for all failures, and more than one can apply to a single failure.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

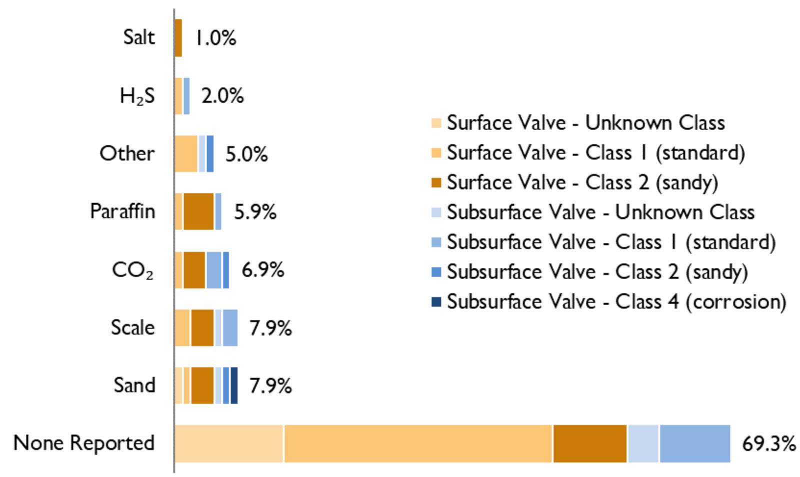
Contaminants and Valve Class

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.

The analysis of contaminants presented in this section includes only failures reported to SafeOCS because failures identified in other sources (APM, INC, OGOR-A, or WAR data) included little information on contaminants. Contaminants were listed for 31 of 101 failures (30.7 percent) reported to SafeOCS, shown in Figure 34, 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 can be one of two service classes:

- Class 1 indicates a performance level requirement intended for use on wells that do not exhibit the detrimental effects of sand erosion.
- Class 2 indicates a performance level intended for use if a substance such as sand could be expected in the flow stream.

Figure 34: Well Stream Contaminants, 2020



NOTE: Percentage is of 101 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 Program.

Five SSV failures indicated the presence of sand, and three of these involved a Class 2 valve. Ten SSV failures indicated the presence of other solids (paraffin, scale, or salt) in the well stream, and seven of these involved a Class 2 valve. Of the total 77 SSV and BSDV failures reported to SafeOCS in 2020, 40 (51.9 percent) were Class 1, 23 (29.9 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.

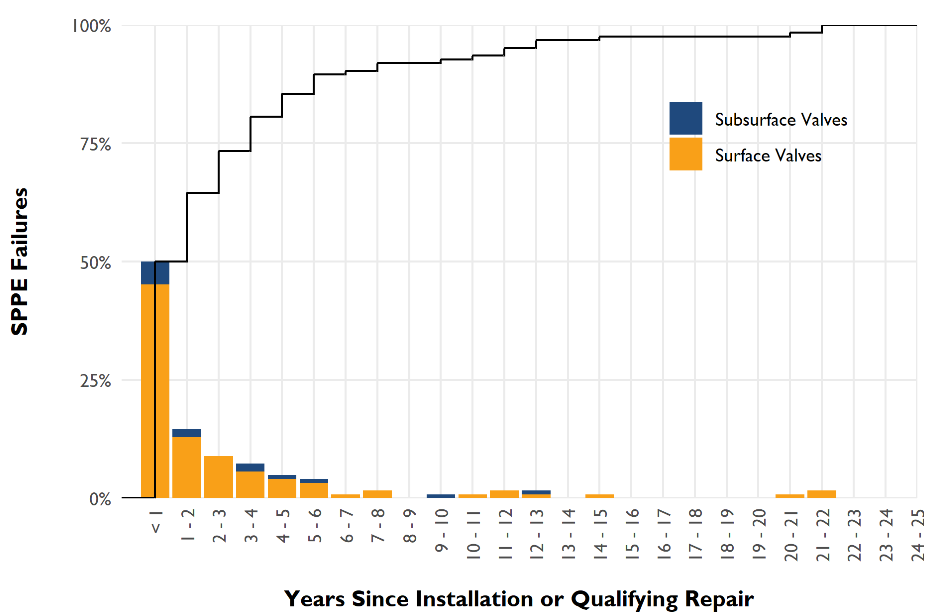
Three SCSSV failures indicated the presence of sand, and one of these involved a Class 2 valve, and one was missing the valve class. Five SCSSV failures indicated the presence of other solids (paraffin or scale) in the well stream, and none of these were reported as a Class 2 valve (three were Class 1 valves, and two did not report the valve class). Of the total 23 SCSSV failures reported to SafeOCS in 2020, 13 (56.5 percent) were Class 1, two were Class 2, one was both Class 1 and 2, one was Class 4, and the remainder did not report the service class.

Nearly all reports of solid contaminants—e.g., sand, paraffin, scale, salt—to SafeOCS came from the top three reporting operators (18 of 21 reports, or 85.7 percent). The top three reporting operators also contributed most of the reports of failures of Class 2 valves (19 of 26 or 73.1 percent).

Time to Failure

To further explore what constitutes normal wear and tear, an analysis of SPPE time to failure was performed. For 124 failures reported to SafeOCS from 2017-2020, the reporter provided either the date of installation or the date of last repair in the narrative description or the redress history. For purposes of this analysis, the repair date was used as a surrogate for the installation date, i.e., the qualifying repair date, if the repair included replacement of 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

Figure 35: Time to Failure, 2017-2020

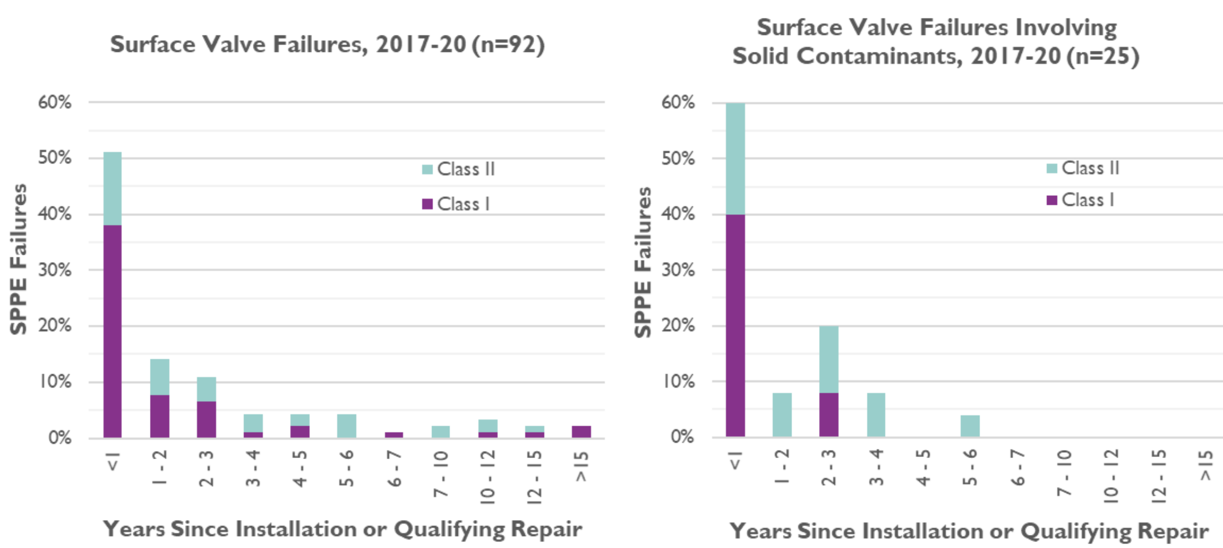


NOTE: Percentage is of 124 failures reported to SafeOCS where the installation date or qualifying repair date was available.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

included replacing those components. The reported dates of installation or qualifying repair ranged from less than one year to greater than 20 years, as shown in Figure 35. For 50.0 percent of these failures (62 of 124), the valve failed within one year, and for nearly three-quarters of these failures (91 of 124, or 73.4 percent), the valve failed within three years. The 124 valves comprised 110 surface valves (107 SSVs, 2 BSDVs, and 1 GLSDV) and 14 subsurface valves (8 SCSSVs and 6 SSCSVs).

To evaluate whether the earlier-life failures (0-3 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 36 shows the distribution of 92 surface valve failures from 2017-2020 that reported both installation or qualifying repair date and the valve service class (left) and the distribution for 25 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 (52.2 percent vs. 23.9 percent from the 76.1 percent of failures during 0-3 years), and more Class 2 valves were involved in failures that occurred after three years (8.7 percent vs. 15.2 percent from the 23.9 percent of failures after 3 years). The chart at right shows that about half (52.0 percent) of the failures that also reported solid contaminants (e.g., sand, scale, paraffin) involved Class 2 valves, and all the Class I failures occurred in the first three years.

Figure 36: Time to Failure and Valve Service Class, 2017-2020



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 91 SSVs and one BSDV, and right panel includes 25 SSVs.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Time to failure analyses are limited by incomplete data. The 2020 form revision added new fields to capture installation date and repair date, which should increase the quantity and quality of the time to failure data collected in the coming years. Well completion date was considered a potential surrogate measure of the valve installation date. Still, a comparison between well completion date and installation date showed large differences in some cases, particularly for older wells where the SPPE was more likely to have been replaced in the intervening years.

Repeated Failures

Thirteen (13) of the 101 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. The failures occurred on 11 SSVs and one SCSSV, with one of the SSVs experiencing two events. Five operators reported the 13 events, 11 of which were reported by the top three reporting operators. The events are summarized in Table 7.

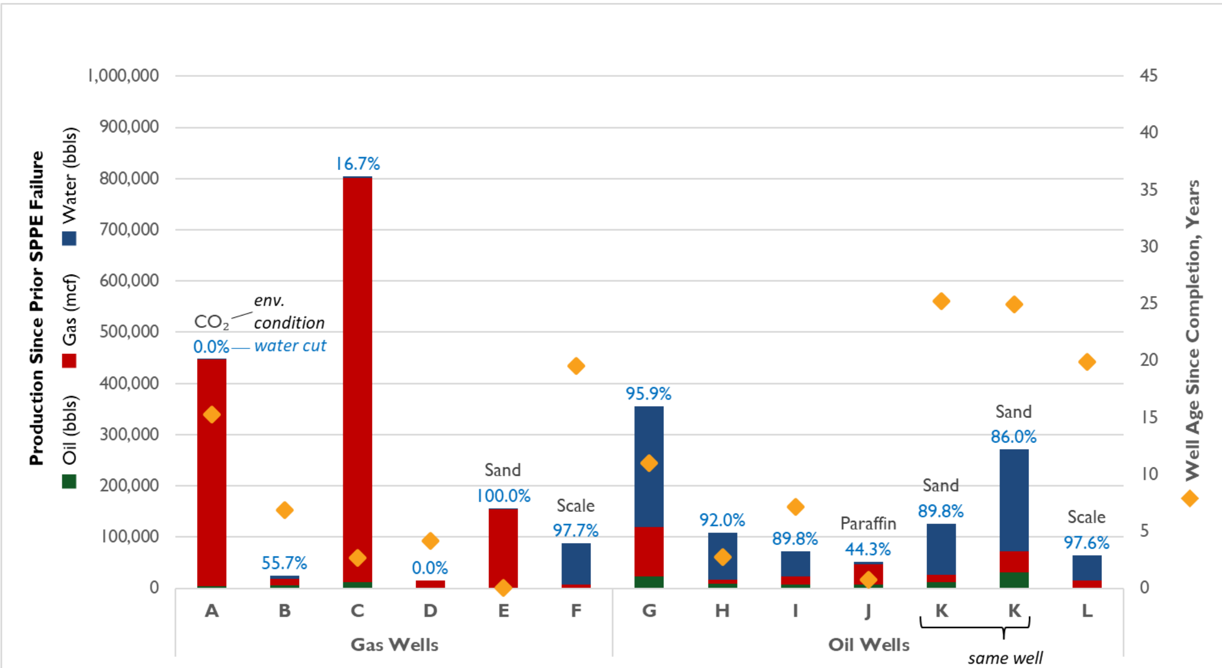
Table 7: Overview of 2020 Repeated Failures

	SSV Failures	SCSSV Failure
Number of Failures	11	1
Components Involved	Gate and seats for 11 events, and valve body for 1 event.	Hydraulic control system.
How Prior Failures Were Corrected	Nearly all reported replacement of the gate and seats. The remainder reported simply that the valve was repaired, which for gate/seat failures typically means the components were replaced.	Control lines were cycled to resolve a blockage in a hydraulic control line.
How 2020 Failures Were Corrected	Same as prior failures.	Not reported, but the well was able to restart production.
Event Type	All gate/seat failures were internal leaks. The valve body failure was a small external leak of produced fluids.	Failure to close when commanded.
Detection Method	All gate/seat failures were found during leakage tests. The valve body failure was detected when the valve was activated during normal well operations.	Bringing well back online following shut-in for storm evacuation.
Root Cause	Wear and tear.	Maintenance plan and procedure.
Contributing Factors	Valve seat degradation, sand cut erosion, scale build-up, and in one case chemical corrosion. Sand or scale was reported for 5 of the 11 events. Four of the gate/seat failures involved a Class 2 valve.	Hydraulic power failure for prior event and chemical corrosion for 2020 event.

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

Figure 37 shows the production volumes, environmental conditions, and age of wells with repeated failures. The production volumes shown reflect the cumulative fluids that passed through the valve from the time of the prior failure until the repeated failure. Most of the repeated failures (eight of 13) were on wells with higher water cut (≥86.0 percent water cut), and seven failures involved a well stream contaminant. Five failures occurred on wells completed within the last five years, and two of these failures were on wells completed within the last year.

Figure 37: Production from Wells with Repeated Failures, 2020



NOTE: Includes 13 repeated failures on 12 wells. Well A had an SCSSV failure, and the other wells had SSV failures. Status as gas or oil well determined from OGOR-A well status at the time of the failure.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

5 CONCLUSIONS AND NEXT STEPS

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 contributing factors and causes. This year's report provides more detail on exposure data and well characteristics used to support analyses, including the following.

- Production rates and well shut-in status were analyzed to determine vital statistics during the pandemic.
- The well status (i.e., producing or non-producing oil or gas completion) at the time of failure was analyzed and compared to the well status across the well population.
- An additional data source—APM—was used along with the INC, OGOR A, and WAR data sources to identify failures that may not have been reported to SafeOCS. To the extent practicable, 2020 failures identified in APM, INC, OGOR-A, and WAR data were included in aggregate analyses.
- The failure rate methodology was refined to account for the variability in the testing frequency of SSVs on shut-in wells. The 2020 rate of SPPE failures in the GOM OCS was at or below 2019 failure rates for all valve types.
- To identify characteristics of wells with more frequent SPPE failures, disproportionality analyses were conducted for a variety of parameters, including water depth, well status as producing or non-producing, and well rate characteristics. This year, relative to the distribution of producing wells, more SPPE failures occurred on wells with higher gas-oil ratios.
- Time to failure was studied for all failures with available data since 2017.
- Analyses comparing four years of data (2017-2020) were presented for event type, corrective actions, and contributing factors.
- Repeated failures, in which the same component of the same valve failed within 12 months, were further evaluated as to the well age and cumulative production volumes that have passed through the valve since the previous failure. High water cut and contaminants may have contributed to the short valve life in these cases.

Some general observations can be drawn from the 2020 data and analyses:

- As in previous years, no failure resulted in HSE incident, i.e., an event with consequences to health, safety, or the environment as defined in Appendix F.
- Although the number of failures reported annually had grown each year from 2017 to 2019,

2020 failures fell dramatically. As in previous years, a few operators reported most failures, with three of 14 reporting operators accounting for 69.3 percent of the failures reported to SafeOCS.

- 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. No SSCSV or USV failures were reported to SafeOCS in 2020.

Next Steps: Opportunities for Improvement

The implementation of the revised form in 2020 is expected to produce better quality of information which can lead to more informative analyses and learnings. In addition, BTS has identified several focus areas for next steps:

- Continue efforts to improve exposure data and measures for the following topics:
  - Measuring component life, in cycles and time, to evaluate the testing and replacement frequencies.
  - Quantifying operational impact in terms of production interruptions and deferrals when failures occur.
  - Enhancing analyses of SPPE failure rates in subsea versus surface wells through evaluation of subsea versus surface well population data for the GOM OCS.
  - Enhancing analyses involving well characteristics and their relationships to SPPE failures.
- Work with stakeholders to improve the data collection process by focusing in the following areas:
  - Identify opportunities to improve reporting of specific root cause failure analysis results and learnings that may have industry-wide benefit.
  - Promote coverage, completeness, accuracy, and timeliness of data collected using the revised form.

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.[24] 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.[25]

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*

[24] Final Rule, 81 Fed. Reg. 61,833 (Sept. 7, 2016).
[25] 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).

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.[26]

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).[27]

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

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

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

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

Production Master: See Master Valve.

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

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

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

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.[28]

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."

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.

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

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.[29]

[29] 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

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

Figure 38: SPPE Annual Report Steps

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

WAR and Non-Rig WAR Reports

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

Application for Permit to Modify (APM)

Operators must submit an APM to BSEE for approval of most well completion, workover, or decommissioning operations.[30] Well intervention operations needed to repair subsurface safety valves are approved by BSEE via APMs. 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.[31] 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. 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

[30] 30 CFR 250.513, 250.613, 250.1712, 250.1721.
[31] 30 CFR 250.1151(a)(2), 250.1204(b).

rate. The equivalent gas rate is equal to the gas volume (in mcf) divided by 5.62.[32] 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 of the failure or the month prior to the failure.

The well rate range for each of the producing wells in the 2020 OGOR-A database (including those with a reported SPPE failure) was determined by BTS using the average production rate for each well during the representative month of December 2020. 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 December 2020, and then dividing the sum of those two volumes by the number of days the well was in production in that month. A similar method was used to determine each of the well rate ranges for oil, gas, water, total liquids, GOR, and water cut during December 2020.

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.

[32] 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 Shut-in Status Codes in OGOR-A

In addition to each well's produced volumes, the OGOR-A data contains various monthly codes for the status of each shut-in well called "shut-in reason codes." Two of the shut-in codes indicate when wells are shut in for SSV problems (code 63) or subsurface safety valve problems (code 45). If the first month that the well status was reported as 63 or 45 was in 2020, BTS counted it as an SSV or subsurface safety valve failure, respectively. OGOR-A data does not provide any additional information about the failure. Since the data is monthly, determining the actual failure date of the SPPE is not possible.

SPPE Population in the Gulf of Mexico

All SPPE installations are reported to BSEE, and these are captured in a database provided by BSEE to BTS. The database includes fields such as type of SPPE, date of installation, date of removal (if removed), removed from service flag, well API number, and other information. BTS used this information to determine the number of currently active SSVs, USVs, BSDVs, SCSSVs, SSCSVs, and GLSDVs in the GOM. This improved the population estimate and allowed the population to be reported by SPPE type. BTS determined the number of active SPPE valves by restricting the list of installed valves to those in the GOM OCS that were not flagged as removed or out of service.

Incidents of Noncompliance (INCs)

BTS reviewed INCs issued by BSEE in 2020 to determine if the deficiency described in the INC was a reportable SPPE failure.[33] The SPPE failures identified in INC data are listed in Table 8. The INCs were then used to cross-reference the SPPE failures during the same period to determine if they

Table 8: SPPE Failures Identified in INC Data, 2020

PINC	Number of SPPE Failures	Short Description
P-280	16	SSV failed to close within 45 seconds
P-412	13	SSV, USV, or BSDV had internal leakage
P-240	5	SCSSV was not tested every 6 months
G-111	3	SPPE corroded or leaking and needing repair
P-307	2	SSV was not tested monthly
P-103	2	SPPE bypassed or blocked out of service
P-319	1	BSDV was not tested monthly
G-112	1	SPPE leaking hydrocarbons externally
P-261	1	Long term shut-in well SCSSV rendered inoperable
Total	*44*	*Total number of SPPE failures identified in INCs*

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

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

were also reported in SafeOCS.

Boreholes Data

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

Well API Number

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

Well Count Determination from OGOR-A Data

The total GOM OCS well count was determined using production data from 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 2020. The active wells were similarly counted for each operator, in addition to the operators' total production.

APPENDIX E: TYPICAL SPPE VALVE COMPONENTS

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

Table 9: Typical SPPE Valve Components

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

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

APPENDIX F: HSE INCIDENTS

A health, safety, and environment (HSE) incident can generally be defined as an event that results in consequences to health, safety, or the environment. For purposes of this report, an HSE incident is an event that results in consequences to health, safety, or the environment above a specified threshold, as detailed below:

- 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 < 10,000 gallons (238 bbl)