SURFACE-CONTROLLED SUBSURFACE SAFETY VALVE EVENTS

From the U.S. Gulf of America
Outer Continental Shelf

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Abstract

This summary of tubing retrievable surface controlled subsurface safety valve (SCSSV) failure history on the U.S. Gulf outer continental shelf quantifies and qualifies known failures with a distinction between valve types used on surface tree and subsea well applications.

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Executive Summary

Purpose and Scope

Offshore oil and gas operations rely on surface controlled subsurface safety valves (SCSSVs) to support well integrity. These valves protect personnel and the environment by controlling the flow of well fluids, especially in the case of emergency or system failure. It is important to monitor the performance of SCSSVs and conduct analyses to identify potential trends and emerging issues that can be considered and addressed by the industry to ensure reliability and performance of these critical safety valves.

This report includes a review of data on events involving tubing retrievable (TR) SCSSVs from 2017 through 2024. It uses regulatory failure definitions and combines industry data, original equipment manufacturer (OEM) input, and literature reviews to assess how design, environment and maintenance affect performance as depths increase. For more background information about TR SCSSV development, design and features, consult Section 1 (Background) of this report.

SafeOCS (www.SafeOCS.gov) is a confidential, industrywide database that collects and analyzes near-miss and precursor safety events in energy operations on the outer continental shelf (OCS). Sponsored by the Bureau of Safety and Environmental Enforcement (BSEE) and administered independently by the Bureau of Transportation Statistics (BTS), SafeOCS works to share information on critical safety equipment and operations while protecting data confidentiality.

Key Findings

In addition to findings related to failure types, rates, causes and contributing factors, this report presents a summary and grouping of SCSSV design and configuration options beginning in Section 1.2 (SCSSV Types and Features), a novel contribution to related literature and broader industry knowledge. The concept was developed with input from SCSSV OEMs and considers common categories of features to distinguish different designs installed in the Gulf of America (GOA). It is intended to facilitate the evaluation and trend analysis for SCSSV types with different models and manufacturers but similar features and potential risk profiles.

Other key findings include:

- Removal of a failed SCSSV for in-depth root cause failure analysis is typically performed only when lower cost alternatives for restoring functionality are unsuccessful and the well is expected to remain profitable even after sustaining such costs.
- Improvements in design may take years to implement due to the large population of active wells with TR SCSSVs and the relatively small number of new installations each year.
- SCSSVs in deeper wells, which are usually subsea, primarily use nitrogen charged valves that have experienced seal failures leading to failures to open, failures to close, external leaks of control fluid, and potential leaks of hydrocarbons.

Conclusions

Section 3.1 of the report (Conclusions) outlines several insights about SCSSV data, including:

- Although industry has implemented design improvements to address rod-piston seal failures in nitrogen-charged SCSSVs, hundreds of similar valves still operate in GOA wells and may be at risk of similar failures.
- Improved operational surveillance reduces the risk of hydrocarbon leaks, but deferred production remains the main consequence when an SCSSV fails to open.
- Adopting a standardized, industry-wide definition of valve failure could improve data quality and completeness and speed the identification of emerging issues.

Information Sharing and Next Steps

This report is intended to support OEMs and operators in understanding SCSSV challenges industrywide. OEMs may also request tailored datasets from BTS, which maintains an extensive eight-year repository of failure records across operators. To strengthen lessons learned, BTS encourages OEMs and operators to confidentially submit investigation reports and corrective actions to BTS. For questions or to share information, contact the SafeOCS team at SafeOCS@dot.gov.

1. Background

SafeOCS is a confidential reporting program for collecting and analyzing data to advance safety in energy operations on the outer continental shelf (OCS). The objective of SafeOCS is to capture and share essential information across the industry about accident precursors and potential hazards associated with offshore operations. The program is sponsored by the Department of the Interior's Bureau of Safety and Environmental Enforcement (BSEE) and operated independently by the Department of Transportation's Bureau of Transportation Statistics (BTS), a principal federal statistical agency. BTS protects the confidentiality of all data submitted to SafeOCS under the Confidential Information Protection and Statistical Efficiency Act (CIPSEA).[1]

Among other safety-data-related activities, SafeOCS collects data and publishes analyses of safety and pollution prevention equipment (SPPE) valve failures, which include failures of six different safety valves:

- Surface safety valve (SSV)
- Surface controlled subsurface safety valve (SCSSV)
- Boarding shutdown valve (BSDV)
- Gas lift shutdown valve (GLSDV)
- Subsurface controlled subsurface safety valve (SSCSV)
- Underwater safety valve (USV)

These valves protect personnel and the environment by controlling the flow of well fluids, especially in cases of emergency or system failure. Regulations pertinent to SPPE are contained primarily in 30 CFR part 250, subpart H, which was first published in 1988.[2] Since 1998, the regulations have required all new SPPE installations to be manufactured under a recognized quality assurance program.[3]

Per 30 CFR 250.803, operators must submit a failure notification to SafeOCS when an SPPE valve does not performed as designed. In 2022, two events involving leaks of well fluids from surface controlled subsurface safety valves (SCSSVs) to the sea in the Gulf of America (GOA) raised concern about the reliability of SCSSVs and the potential for similar events to occur in the future. The original equipment manufacturers (OEMs) are also keen to gain a broader view of SCSSV performance in the GOA in the challenging operating conditions for which the valves are designed. The purpose of this report is to respond to regulatory and equipment manufacturer requests to BTS to provide information on SCSSV events reported to SafeOCS.

This report summarizes how SCSSV designs have evolved as offshore well depths have increased. Although designs have evolved to meet technical challenges related to the higher pressure and temperature conditions in deeper wells, design issues continue to be cited as

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[1] Confidential Information Protection and Statistical Efficiency Act of 2018, 44 U.S.C. 3561–3583, also known as Title III of the Foundations for Evidence-Based Policymaking Act of 2018, Pub. L. No. 115-435.

[2] Final Rule, Oil and Gas and Sulphur Operations in the Outer Continental Shelf; Outer Continental Shelf Minerals and Rights-of-Way Management, General; and Outer Continental Shelf Orders for All Regions of the Outer Continental Shelf, 53 Fed. Reg. 10596 (Apr. 1, 1988). Quality assurance requirements for SPPE were codified at 30 CFR 250.126 (1988).

[3] Final Rule, Safety and Pollution Prevention equipment Quality Assurance Requirements, 62 Fed. Reg. 42669 (Aug. 8, 1997). The current SPPE certification requirement is codified at 30 CFR 250.801 (2025).

contributing factors to SCSSV failures. In 2023, 27.8 percent of reported subsurface safety valve failures cited "Design Issue" as the root cause.[4]

Per 30 CFR 250.803, an SPPE failure is "any condition that prevents the equipment from meeting the functional specification or purpose."[5] This includes failures to function as intended regardless of whether the corrective measure involves removal, repair, or replacement of failed parts. For example, failing a leakage rate test and correcting by chemically soaking and cycling the valve is considered a reportable failure under the regulation despite the corrective measure. Therefore, failures can occur anytime during the valve lifecycle, including in the design, build, operate, and maintain phases.

Examining the failure rates of various valve types may help identify best practices and designs or applications for SCSSVs to minimize risk of failure. Failure rate determination involves comparing the number of failures of a certain valve type to the population of installed valves of that type. While SCSSV population data is not readily available in tabular form, this report attempts to characterize the population to establish comparable failure rates for various types of SCSSVs. There are two primary types of SCSSVs: tubing retrievable (TR SCSSV) and wireline retrievable (WR SCSSV). This report primarily presents data analysis related to TR SCSSVs.

BTS relied on the following information sources in the development of this report: SafeOCS equipment failure data, review of literature on SCSSV designs, input from meetings with SCSSV OEMs and product literature from OEMs or their websites.

1.1. SCSSVS IN THE GULF OF AMERICA

Per regulation, an SCSSV is required to be installed according to the American Petroleum Institute (API) Specification 14A and Recommended Practice 14B in every well in the GOA.[6] SCSSVs are typically tubing retrievable valves that are installed during the original construction of the well. The basic design of the SCSSV includes a sealing element, usually a flapper or a ball, that is operated by a control system. "Surface controlled" refers to the type of valve that is operated by hydraulic fluid connected from the surface to the valve by a hydraulic control line (or two control lines in the case of a dual control system or where a balance line is used). The hydraulic line is routed from the surface (the topsides hydraulic control system) through the annular space between the casing and the tubing. In the case of a subsea well, the hydraulic line must also travel through the umbilical to the subsea tree before entering the well annulus.

In the case of a TR SCSSV failure, the well must be shut in, deferring production until the failure can be addressed. In some cases, cleaning, exercising, or cycling the valve can correct the issue. If those remedies are not successful, there are limited options available to restore downhole safety valve reliability so that the well can produce again. If the control system is still functioning correctly, a wireline retrievable (insert) SCSSV can be installed in the nipple profile

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[4] Bureau of Transportation Statistics. *Oil and Gas Production Safety System Events – 2023 Annual Report*. Washington, D.C.: United States Department of Transportation, 2023. https://doi.org/10.21949/npq3-tr53. See Figure 20, page 33.

[5] 30 CFR 250.803 (2025).

[6] 30 CFR 250.802(b) states, "All SSSVs and their actuators must meet all of the specifications and recommended practices of ANSI/API Spec. 14A and ANSI/API RP 14B". CFR 250.814(d) (for dry trees) and CFR 250.828(c) (for subsea trees) state "You must design, install, maintain, inspect, repair and test all SSSVs in accordance with … ANSI/API RP 14B."
CFR 250.198(e)(87) Documents incorporated by reference: ANSI/API Spec. 14A, Specification for Subsurface Safety Valve Equipment, Eleventh Edition, October 2005, reaffirmed June 2012.

of the original SCSSV. In cases where the control system is not functioning properly, the insert valve may not be an option, depending on whether the integrity of the control system has been compromised. In that case, the SCSSV must be pulled and repaired or replaced, which requires a rig to pull the tubing down to the SCSSV. In certain situations, the operator may obtain permission from BSEE to convert the well's subsurface safety valve to a subsurface controlled subsurface safety valve (SSCSV).

SSCSVs are not permitted in subsea wells per 30 CFR 250.802(b). Furthermore, WR SCSSVs have only recently become commercially available for ultra deep (> 6,000 ft) applications. In late 2024, the first WR SCSSV was installed in an ultra-deep subsea well.[7] This relatively new valve is rated for 12,500 psi and 300°F and can be used in any TR SCSSV.[8] However, WR SCSSVs are not options for higher pressure or higher temperature wells. Therefore, TR SCSSV reliability is critical to avoiding both costly repair or replacement and weeks of deferred production while the well is shut in.

The 2023 SafeOCS SPPE Annual Report covers failures from 2017 through 2023 when there were 4,254 active wells in the GOA.[9] That year, SafeOCS recorded 69 subsurface safety valve failures, including all types (54 SCSSV, 11 SSCSV, and four where the type of valve that was installed could not be determined). Although some of the SCSSVs in those 4,254 wells have since been replaced with SSCSVs or abandoned, one can estimate the active 2024 SCSSV population to be in the range of 3,900 to 4,000 valves based on the number of active wells in 2024.

Subsea wells, where the wellhead is installed on the seafloor, have been producing in the GOA since the 1970s when the first subsea production system was commissioned.[10] The industry has added an average of 12 new subsea wells in the GOA annually for the past 30 years.[11] Based on an upper estimate of 4,000 wells with active TR SCSSVs, approximately 600 wells with active TR SCSSVs are subsea wells.[12] Subsea wells necessarily differ in the design of the SCSSV control line because the wellhead is installed subsea. Hydraulic control fluid is still provided to the SCSSV from the surface via the umbilical. However, rather than returning the hydraulic control fluid back to the surface, it is commonly vented at the wellhead to the sea when the SCSSV valve transitions. In these cases, the selected control fluid is a water-based fluid.

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[7] Dallimore, Sarah, Max Mondelli, Stuart Dennistoun, Charlotte Prentice, Mahd Dada, Lawrence Ramnath, Celeste Yates, Adam Manlandro, and Stuart William Murchie. "Bespoke Insert Safety Valve Design Installed in Deepwater Gulf of Mexico via Light Well Intervention." SPE/ICoTA Well Intervention Conference and Exhibition, March 18, 2025. https://doi.org/10.2118/224068-ms.

[8] Baker Hughes. "REACH Wireline Retrievable Safety Valve (WRSV)." 2022. PDF file. Accessed December 1, 2025. https://dam.bakerhughes.com/m/3d1a11192e139dac/original/REACH-wireline-retrievable-safety-valve-slsh.pdf.

[9] Bureau of Transportation Statistics. *Oil and Gas Production Safety System Events – 2023 Annual Report*. Washington, D.C.: United States Department of Transportation, 2023. https://doi.org/10.21949/npq3-tr53.

[10] Viper Innovations. "A Timeline of Subsea Innovation in the Oil & Gas Industry, 1940–2000 — Part One." Accessed December 1, 2025. https://www.viperinnovations.com/a-timeline-of-subsea-innovation-in-the-oil-gas-industry-1940-2000-part-one/.

[11] Based on BSEE valve installation data on where USVs are installed with no indication that they have been removed.

[12] BTS estimated the number of active USVs using BSEE provided SPPE valve installation data. Specifically, the count assumes that active subsea wells are those with USVs installed in the GOA without a removal flag or out of service flag or removal date, assuming that no more than two USVs are installed on a well and two USVs are installed on most subsea wells.

1.2. SCSSV TYPES AND FEATURES

TR SCSSVs are installed in the tubing when the well is initially completed. They cannot be removed from the well without removing the tubing down to the SCSSV, which requires a rig workover. As such, the TR SCSSV is designed to last the life of the well. In cases where a failed TR SCSSV's functionality cannot be restored by chemical treatment, exercising (cycling) the valve, control system adjustments, or other remedies, an insert type SCSSV can be installed in the nipple profile. The insert type SCSSV is also called a wireline retrievable SCSSV because it can be installed and retrieved using wireline equipment. Another option for addressing a failed TR SCSSV that may be allowed with BSEE approval is to install a subsurface controlled subsurface safety valve (SSCSV). However, in subsea (wet tree) wells, SSCSVs are not allowed, and insert valves (WR SCSSVs) have only recently become available for ultra deep applications, so the reliability of the TR SCSSV is more critical to sustaining ultra deep well production, as compared to surface wells and subsea wells < 6,000 ft deep.

Over the years, TR SCSSV designs have evolved to perform in increasingly deeper wells and their control systems have also evolved to accommodate deeper setting depths and higher pressure and temperature conditions encountered in those deeper wells.[13] Common categories of features that distinguish the different designs installed in the GOA include:

- Actuation mechanism
- Deep-set enabler
- Redundancy
- Closing mechanism
- Equalization
- Actuating system sealing materials

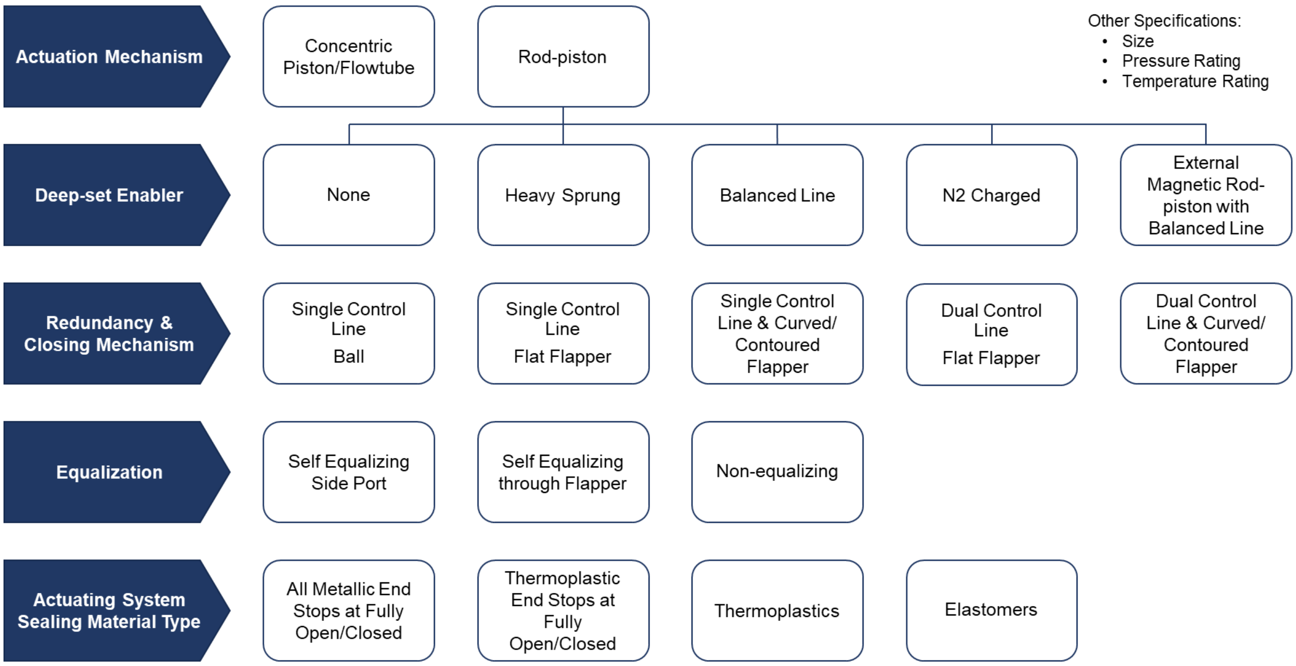
These categories were identified by reviewing the design features described in the API specification for SCSSVs,[14] and through discussions with OEM representatives about the design features that are most closely related to common failure types (internal leak, failure to close and external leak).

To facilitate the evaluation and trend analysis of TR SCSSV types that differ in model and manufacturer but share similar features and potential risk profiles, BTS, with input from OEMs, developed a visual summary of their design features (Figure 1). This summary aided in characterizing the standard and optional features of the different SCSSV models.

[13] Analysis of the API Well Lookup data from the BSEE API Data Center confirms the trend of increasing percentages of well completions in deepwater since around 1990. Design changes to accommodate deeper set depths are confirmed by an analysis of manufacturing dates provided by OEMs for the various TR SCSSV models.

[14] API Specification 14A, Subsurface Safety Valve and Annular Safety Valve Equipment, Thirteenth Edition, March 2024, Section 4.2.

Figure 1. TR SCSSV Design Features



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

Actuation Mechanism

The actuation mechanism describes the mechanism (either a concentric piston or a rod-piston) that converts the control pressure into motion inside the valve. The concentric piston is close in diameter to the tubing size. Standard tubing sizes include 2", 2-3/8", 2-1/2", 2-7/8", 3-1/2", 4-1/2", 5", 5-1/2", 6-5/8", 7" and 9-5/8".[15] The most common sizes in use on the United States OCS are 2-3/8”, 3-1/2”, 4-1/2” and 5-1/2” based on the reported failure data. The rod-piston is much smaller in diameter, and there may be two rod-pistons in a single valve. One OEM described these rod-pistons as about the size of a pencil, and various valve literature diagrams show that each rod piston is opposed by a similar sized spring below it.

Deep-Set Enabler

The deep-set enabler allows the SCSSV to be installed deeper in the well where the hydrostatic head of the control system increases. Section 2.3.1 of this report discusses set depth in more detail. According to OEM product literature, the enabling features for deeper set depths include using a heavier spring with higher closing force, using a balance line to route control fluid to the bottom of the rod-piston, using a nitrogen pressurized chamber to provide opposing force to the bottom of the rod piston, and using a magnetically coupled rod piston with a balance line to make the actuating mechanism independent of wellbore pressure.[16]

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[15] From manufacturer valve literature.

[16] Product literature for currently available SCSSVs is available at each manufacturer’s website. For obsolete models, design, operating and maintenance literature was provided by the OEM to BTS. Websites include: Bakerhughes.com, Halliburton.com, SLB.com, Tejasre.com, and Weatherford.com.

Redundancy and Closing Mechanism

The closing mechanism is the moving part of the valve located in the wellbore tubing to stop the flow of fluid when needed. It consists either of a ball with a flowline sized hole through its center or a flapper, and both types offer metal-to-metal sealing of the wellbore. There are also various types of flappers, such as flat, curved, and slim flappers, described in OEM brochures for various model valves. For this study, we have simply contrasted flat and curved flappers (including contoured flappers). The same row of Figure 1 shows the level of redundancy: single or dual control lines.

Equalization

Equalization is the process of obtaining equal pressures above and below the closing mechanism (typically the flapper) prior to opening the flapper to decrease the required opening forces to within the capability of the control system. Importantly, below the closed flapper is the wellbore or reservoir pressure. In shallower wells, where the hydrostatic head of the fluid column above the flapper is low compared to the reservoir pressure, the pressure above the flapper must be raised by applying external pressure usually requiring pumps and operator attention.

SCSSV manufacturers have invented two common methods to “self-equalize” the pressure before the valve fully opens. These are called “through flapper” and “side-port” equalization in the OEM product literature. The equalization feature may be standard, available as an option, or not available depending on the particular model.[17]

Based on the OEM representatives’ experience, most operators of deeper water wells do not use self-equalizing valves because they are viewed as another potential path for an internal leak through the valve. In addition, OEMs warn that these features can cause erosion damage when used in situations where the differential pressure is higher than the maximum design differential pressure of the equalization feature, which is typically 500 to 1,000 psig. In cases where the differential is expected to be higher, the well will require external equalization to partially lower the differential pressure.

Actuating System Sealing Materials

The bottom row of the diagram describes the options for seal materials in the actuating section of the SCSSV. Rod piston actuating systems typically incorporate piston seals and end stop seals. The piston seal, which is designed to seal the piston and move the valve to an open position, is typically thermoplastic in more modern valve designs. The end stops, which seal the fully closed and/or open valve position to isolate the control system from the wellbore, may be metallic or thermoplastic. Elastomeric seals have been used for a longer period of time, but they are susceptible to chemical attack, high temperature, and rapid gas decompression when exposed to wellbore conditions. Thermoplastics are more tolerant to these threats. Metal-to-metal seals are susceptible to galling and scoring, but they have much higher temperature limits, tolerate sudden pressure changes, and some materials (such as stainless steels and nickel alloys) are more chemical resistant than others.

[17] Per discussions with OEM representatives and confirmation in product literature provided by the OEMs.

1.3. TR SCSSV DESIGN GROUP

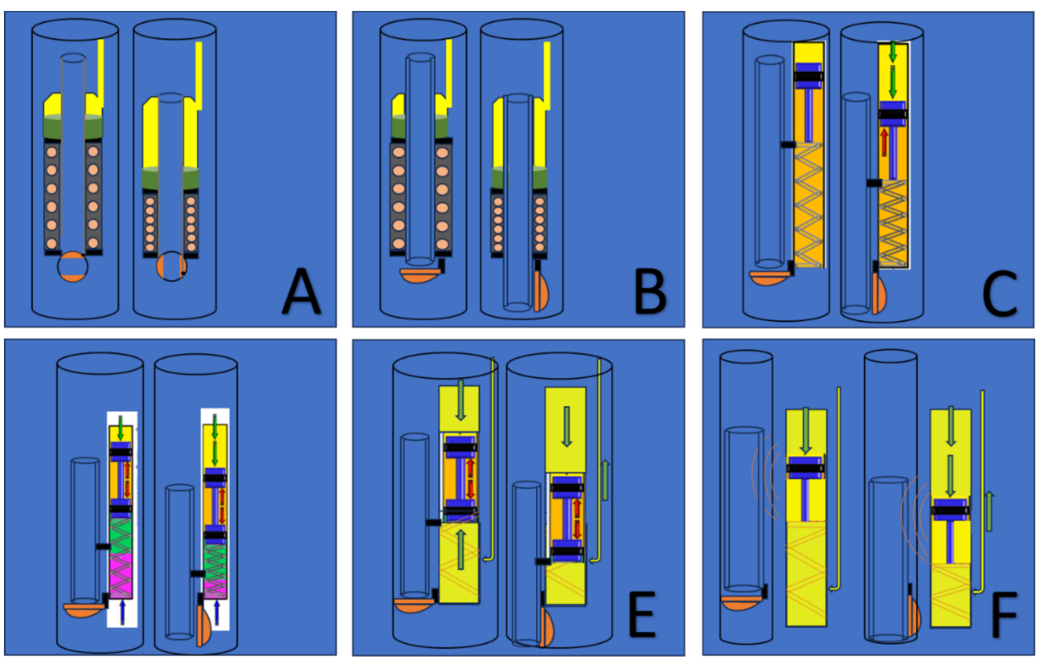
Using the concept presented in Figure 1, BTS, with the assistance of OEMs, classified the design features of 36 SCSSV models manufactured by five OEMs. Design groups were identified based on common attributes. This report separates TR SCSSV designs into the following groups that generally follow the chronological order in which the valve designs were developed.[18]

A. Concentric piston actuated ball valve
B. Concentric piston/flowtube actuated flapper
C. Single control rod piston actuated flapper
D. Dual control nitrogen charged rod piston actuated flapper
E. Balanced line rod piston actuated flapper
F. Magnetically coupled rod piston actuated flapper

All-electric SCSSVs are an emerging technology introduced in 2015 that has been gaining interest in the industry although only one has thus far been installed. An all-electric valve uses an electric motor or solenoid rather than a hydraulic piston to move the valve closure mechanism. With only one installation in the world (none in the GOA), electric SCSSVs are not included as a design group in this study. According to one OEM representative, additional installations are nearing completion in Brazil.

Figure 2 presents conceptual diagrams for these six SCSSV groups' actuating and sealing mechanisms, and they are also described in the following paragraphs.

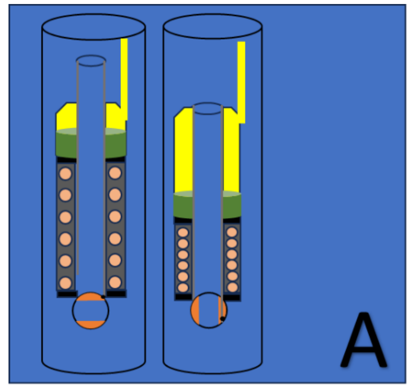
Figure 2. Conceptual Diagrams of TR SCSSV Designs



NOTE: Not to scale.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS. Diagrams C–F developed by BTS with input from SLB.

[18] According to information provided by OEM representatives about the year each model valve was manufactured.

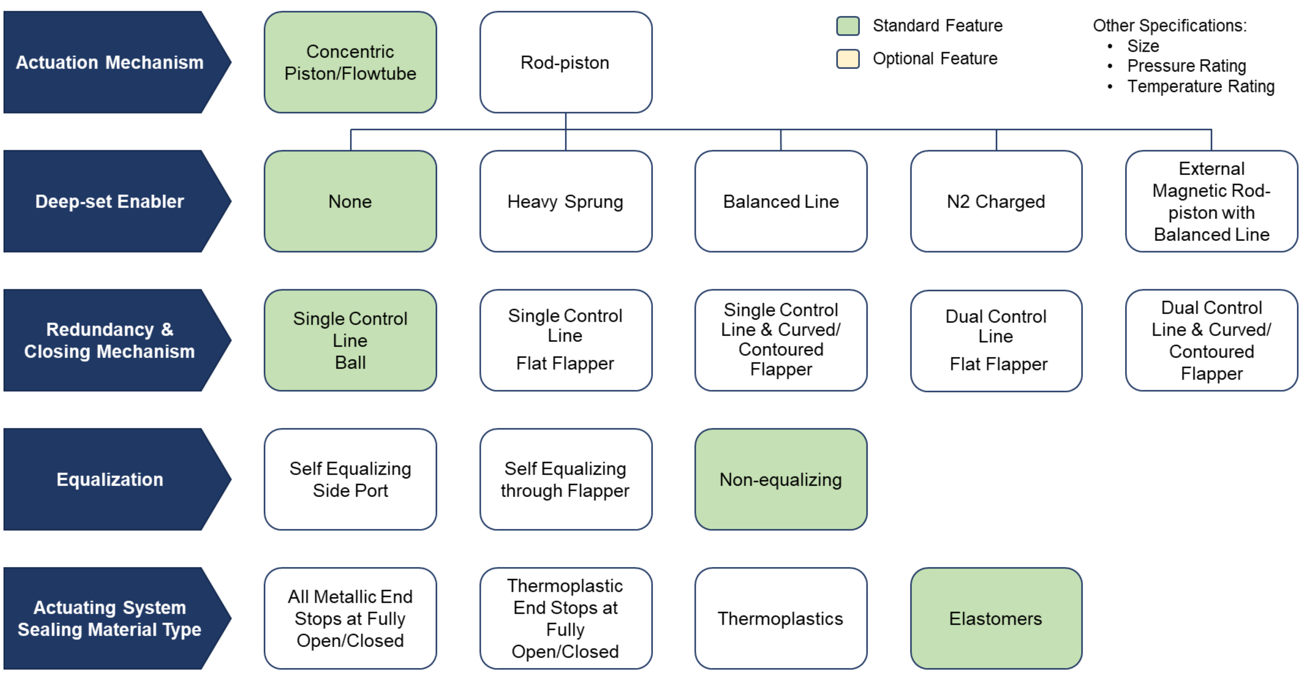
1.3.1. Group A: Concentric Piston Actuated Ball Valve



Some of the oldest TR SCSSVs installed use a ball valve closure mechanism to stop the flow of fluid in the wellbore. These valves are actuated by the application of hydraulic pressure on the concentric piston that is connected to a shifting sleeve. The downward force causes the sleeve to shift downward, rotating the ball to the open position. A hole through the middle of the piston allows wellbore fluids to flow when the ball valve opens (i.e., the ball is rotated such that the hole through the middle of the ball is aligned with the tubing). A large spring that is centered in the tubing below the concentric piston opposes the downward control pressure. It forces the valve to close when there is insufficient control pressure to hold the shifting sleeve down.

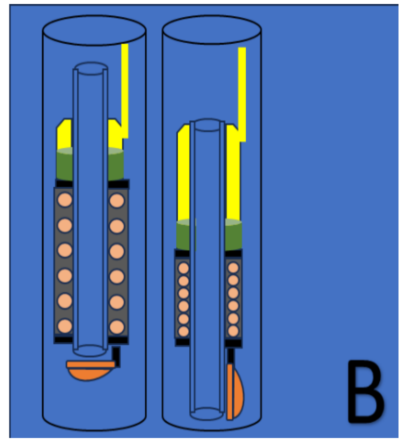
Figure 3 shows the standard features of Group A valves including the concentric piston as the actuation mechanism. No additional features are available that would enable these valves to be set at deeper depths in the well, so they are generally used in shallow water wells (< 1,000 ft water depth). The valves in Group A have a single control line, require equalization of pressure from the topsides, and contain elastomeric seals in the actuating portion of the valve. These valves have been offered in various nominal sizes over the years including 2”, 2-1/2”, 3-1/2”, 4-1/2”, and 5-1/2”. They are typically rated for 5,000 psig and some are rated up to 10,000 psig.

Figure 3. Group A TR SCSSV Design Features



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

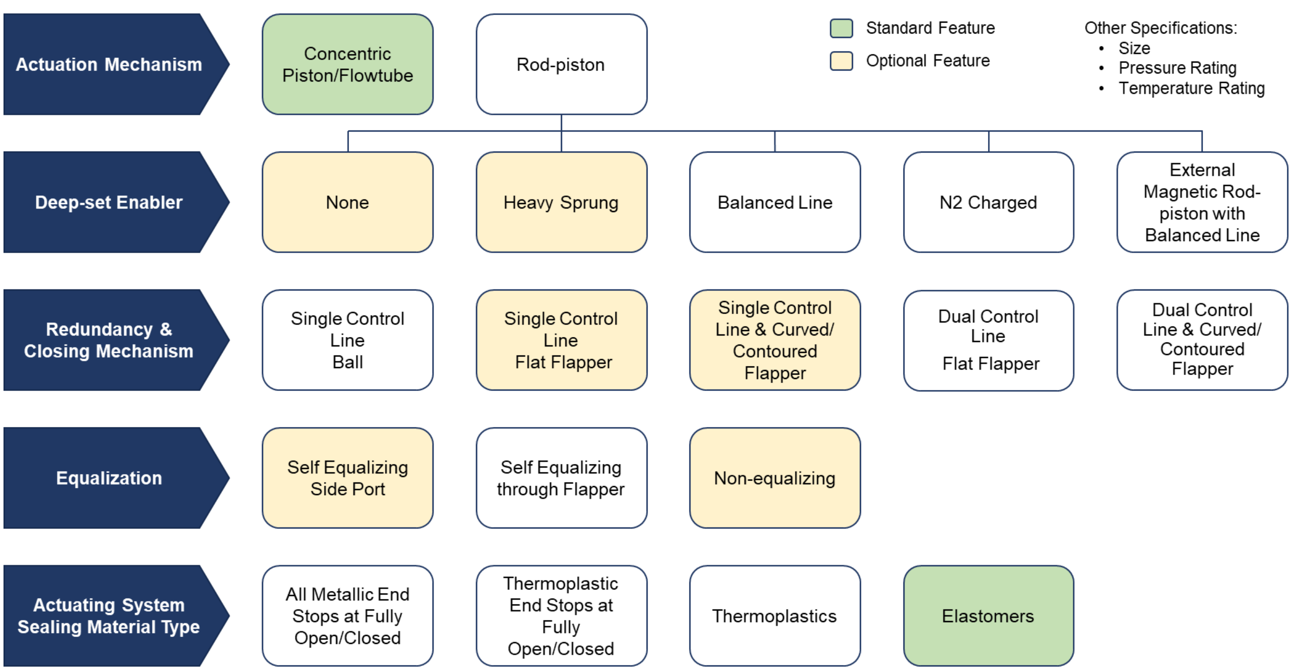
1.3.2. Group B: Concentric Piston/Flowtube Actuated Flapper



Technology advanced from the ball valve to the flapper valves, first introduced in 1959. Models reviewed for this report were introduced to the market in the late 1970s, 1980s and 1990s. The valves in Group B have a flapper closure mechanism, and they are actuated by a concentric piston similar to the ball valves in Group A. The downward force on the piston causes the sleeve to shift downward pushing the flapper to the fully open position. Opposing the control pressure is a large spring that is centered in the tubing below the concentric piston. It forces the valve to close when there is insufficient control pressure to hold the shifting sleeve down.

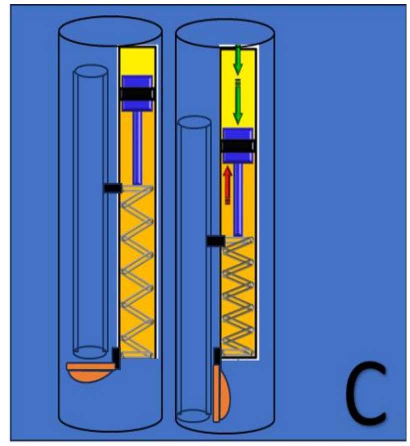
Figure 4 shows the standard features of Group B valves including the concentric piston as the actuation mechanism and either a flat flapper or a curved flapper. Certain models have the option of "heavy sprung" to enable these valves to be set deeper in the well (up to 1,000 ft or 3,000 feet, depending on the model). The valves in Group B have a single control line. They can be either equalizing through a side port or the flapper, or they can be non-equalizing. They contain elastomeric seals in the actuating portion of the valve. These valves have been offered in various nominal sizes over the years including 2", 2-3/8", 2-1/2", 2-7/8", 3-1/2", 4-1/2", and 5-1/2". They are typically rated for 5,000 psig and can be rated up to 10,000 psig. The temperature rating is limited to 275°F or 300°F, depending on the model. Information from discussions with OEMs suggest that the GOA population of Group B valves is relatively large compared to some other design groups.

Figure 4. Group B TR SCSSV Design Features



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

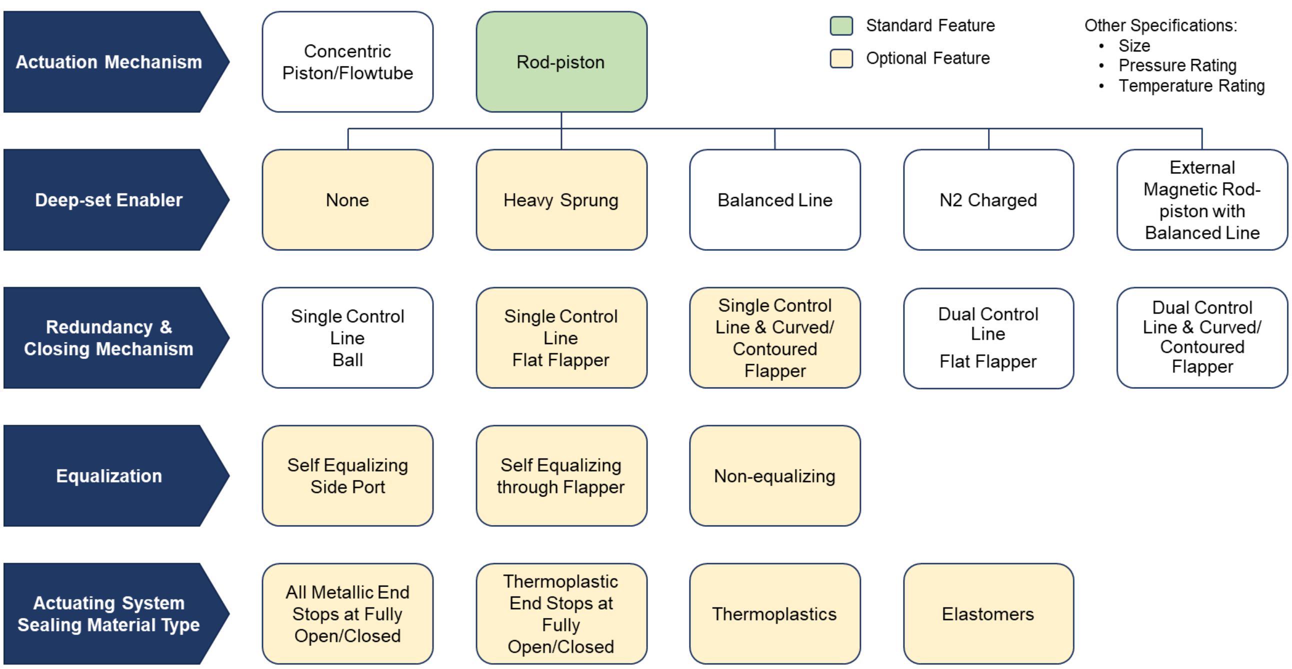
1.3.3. Group C: Single Control Rod Piston Actuated Flapper



The use of a small rod-piston in TR SCSSVs began in 1979 to achieve deeper set depths below the permafrost in Prudhoe Bay, and valves in this group continue to be installed.[19] Rod pistons are more compact, therefore require less hydraulic volume. They are able to operate at deeper water depths, albeit with corresponding higher operating pressures. The rod-piston valves offer a wide range of options, and they are offered by all the OEMs involved in this study. Figure 5 shows the options available in Group C valves, which are the first generation of valves that can be installed in high pressure, high temperature (HPHT) wells.[20]

About 20 models from different OEMs offer varying depth limits, which are typically in the medium set depth range (up to 6,000 ft) with some exceptions of up to 9,000 ft set depth. Over the years certain models have been discontinued and approximately 10 models remain available. Many design features are available as options, which means that the valve can be customized for the particular operating environment expected in the well and to the well completion designer's specifications (e.g., some prefer non-equalizing, and some prefer thermoplastic end stop seals over metal-to-metal). Valves in this group can be found in all nominal sizes except the 2" size.[21]

Figure 5. Group C TR SCSSV Design Features



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

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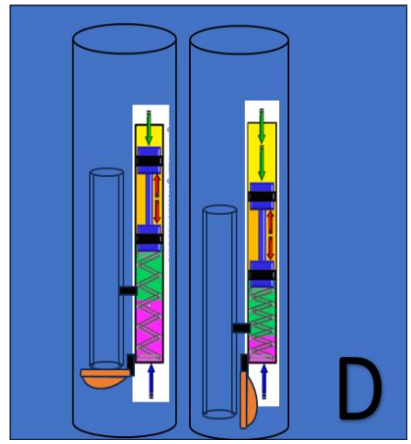
[19] Camco document citing company milestones from 1947 to 1995, on file with BTS.

[20] BSEE regulations define the HPHT environment as a maximum anticipated surface pressure or shut-in tubing pressure of >15,000 psia or a flowing temperature of ≥350°F (see 30 CFR 250.804(b)).

[21] Nominal tubing sizes have included 2-3/8", 2-1/2", 2-7/8", 3-1/2", 4-1/2", 5", 5-1/2", 6-5/8", 7" and 9-5/8".

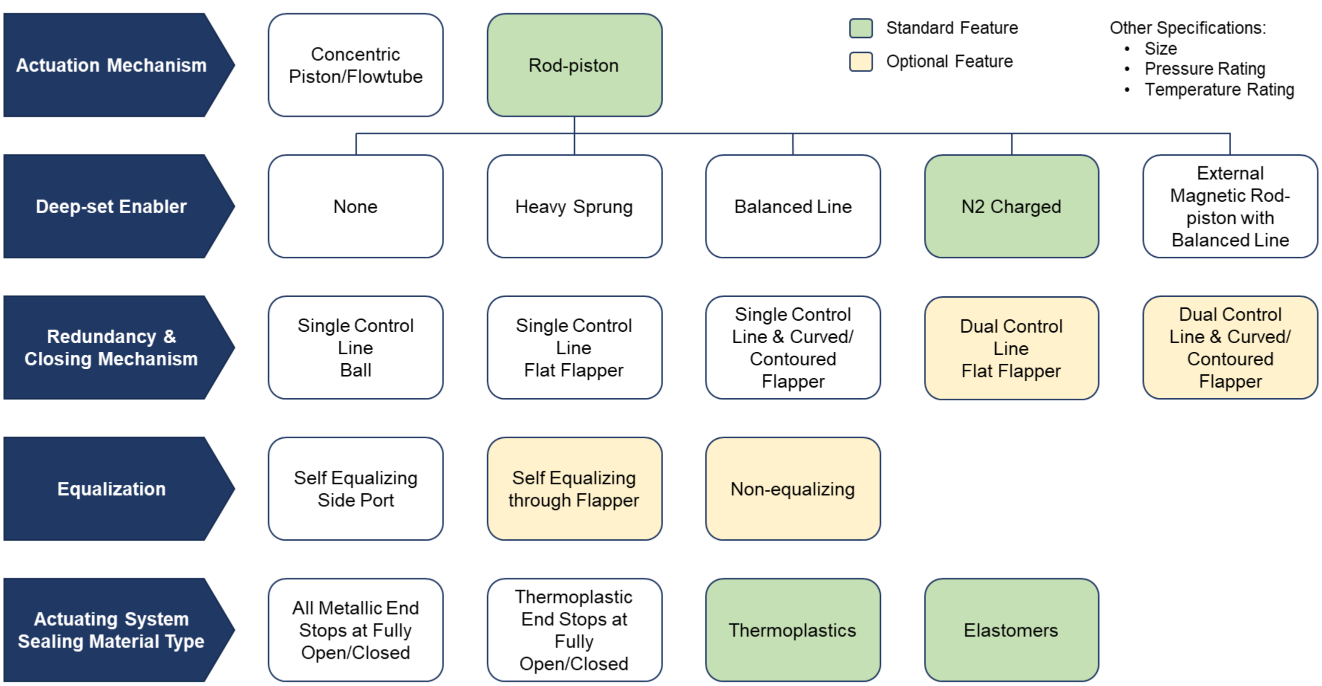
1.3.4. Group D: Dual Control Nitrogen Charged Rod Piston Actuated Flapper



The nitrogen charged SCSSV was developed in the late 1980s to enable even deeper set depths (up to 15,000 ft) without significantly increasing the control system operating pressure. Designs have advanced over the years to combat some issues, such as actuating system sealing, and nitrogen charged valves continue to be installed. In fact, Group D valves have been the mainstay in deepwater subsea wells in the US OCS with an estimated minimum 850 installations.[22]

Figure 6 shows the standard features of Group D valves. The nitrogen charged SCSSVs also use rod-pistons for the actuation mechanism, and there are usually two rod pistons to provide fully redundant control systems. Group D valves are available with flat or contoured flapper, depending on the model. Most nitrogen charged SCSSVs in the GOA are installed as non-equalizing, but an equalizing device through the flapper is also available. Thermoplastic dynamic seals and one elastomeric seal are used in the actuating part of the valve. These valves are offered in 3-1/2”, 4-1/2”, 5.5”, and 7” nominal sizes. The maximum ratings are different with different sizes and models, but they can achieve 20,000 psig pressure rating and 350°F temperature rating.

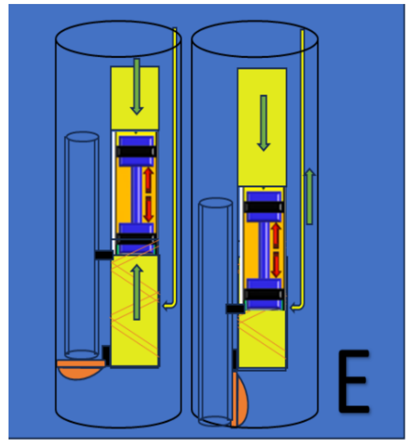
Figure 6. Group D TR SCSSV Design Features



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

[22] BTS developed an estimate of 850 based on BSEE SPPE valve installation data. BTS estimates that approximately 800 of the 850 TR SCSSVs originally set at depths greater than 3,000 ft in active wells remain active. Summing OEM estimates based on GOA portion of worldwide sales of various models yielded approximately 1,500 installations.

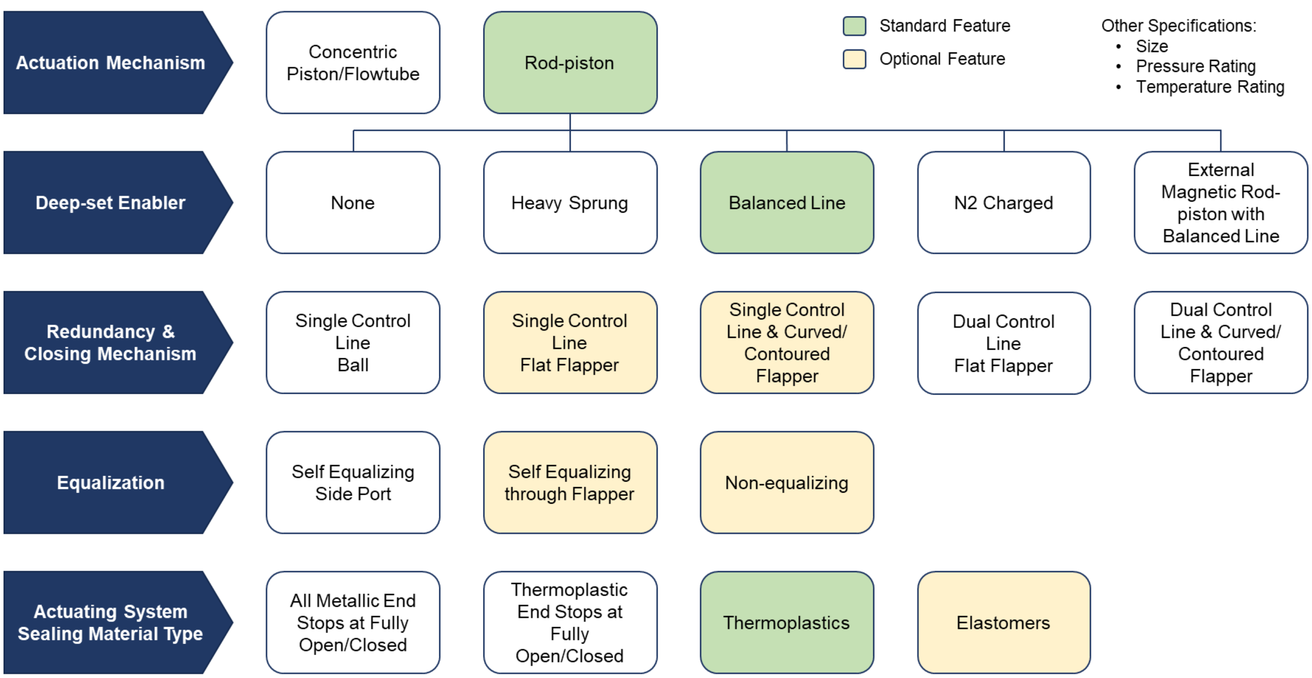
1.3.5. Group E: Balanced Line Rod Piston Actuated Flapper



Another more recent design that enables deeper set depths (up to 20,000 ft) without increasing the control system operating pressure significantly is the balanced line SCSSV; models in this group in this report were introduced around 2020. These new designs have limited installations (estimated to be less than 20) in the GOA because they are so recent.

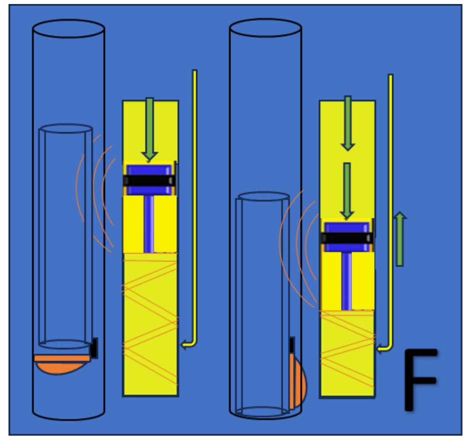
Figure 7 shows the standard features of Group E valves. These TR SCSSVs also use rod-pistons for the actuation mechanism with a single control system that requires two control lines to “balance” the pressure above and below the rod-piston. The Group E valves are available with flat or contoured flapper, depending on the model. Although most installations of balanced line SCSSVs in the GOA are installed as non-equalizing, an option for a self-equalizing device that operates through the flapper is available. Thermoplastic dynamic seals are typically used in the actuating part of the valve, and options for elastomeric seals are available. These valves are offered in 3-1/2”, 4-1/2”, 5-1/2”, and 7” nominal sizes. The maximum pressure rating is different with different sizes and different models, but they can achieve 20,000 psig pressure rating. Temperature ratings up to 400°F are available.

Figure 7. Group E TR SCSSV Design Features



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

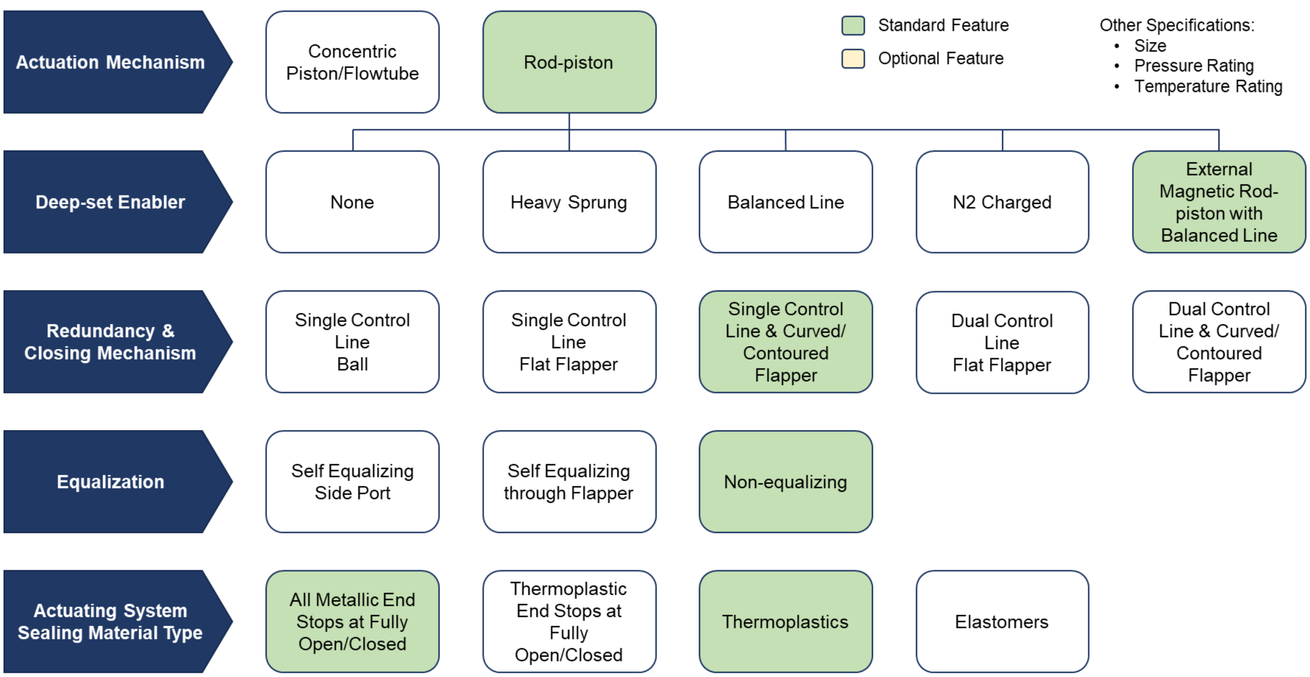
1.3.6. Group F: Magnetically Coupled Rod Piston Actuated Flapper



The Group F designs address the rod-piston seal leakage issue by separating the control system from the wellbore fluids. This is accomplished by magnetically coupling the control rod-piston to the flow-tube, causing the flow-tube to push the contoured flapper open. The design also enables the actuating system seals to be insulated from full wellbore temperatures and exposure to production fluids (oil, gas, and water), including potential contaminants.

The magnetically coupled rod-piston actuated valve utilizes a single control system that requires two control lines to "balance" the pressure above and below the rod-piston, enabling deeper set depths with lower control system pressure. As depicted in Figure 8, there are no options for self-equalization with this valve, which is only available in 4-1/2" or 5-1/2" nominal sizes. They have been manufactured since approximately 2006, and OEMs estimate that there are approximately 50 installations of Group F valves in the GOA.

Figure 8. Group F TR SCSSV Design Features

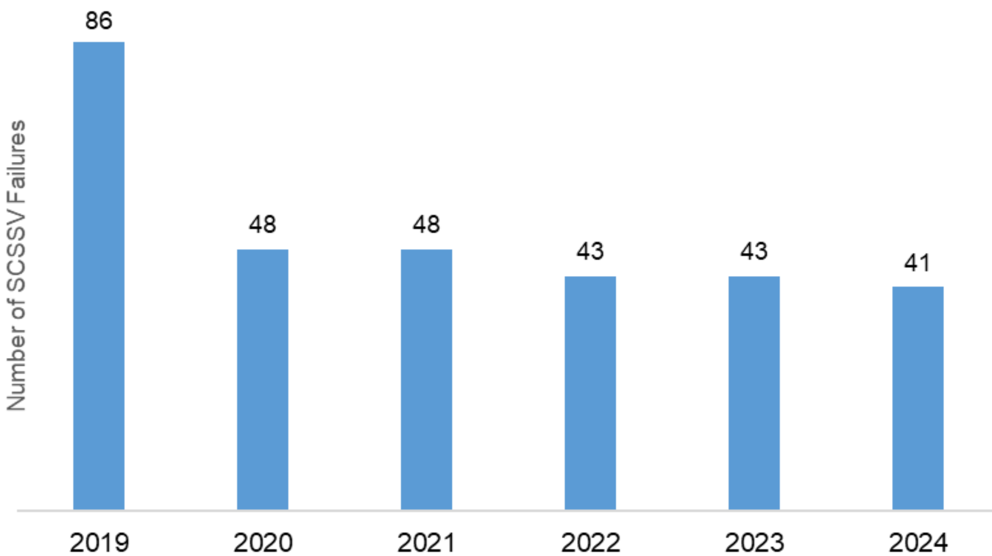


Note: The actuating system seals in this valve group are not exposed to wellbore fluids or operating conditions.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

2. Event Data Analysis

From 2019 through 2024, 309 SCSSV failures were either reported to SafeOCS or found to have occurred through evaluation of other BSEE data sources, including applications for permit to modify (APM), incidents of noncompliance (INC), reported incident data, Oil and Gas Operations Reports – Part A (OGOR-A), and well activity reports (WAR). Figure 9 shows the number of failures each year. The 45 SCSSV failures reported to SafeOCS in 2017 and 2018 are not shown in the figure but are included in relevant analyses in this report.[23] The failure trend generally follows the declining trend of active wells in the GOA.[24]

Figure 9. SCSSV Failures, 2019–2024

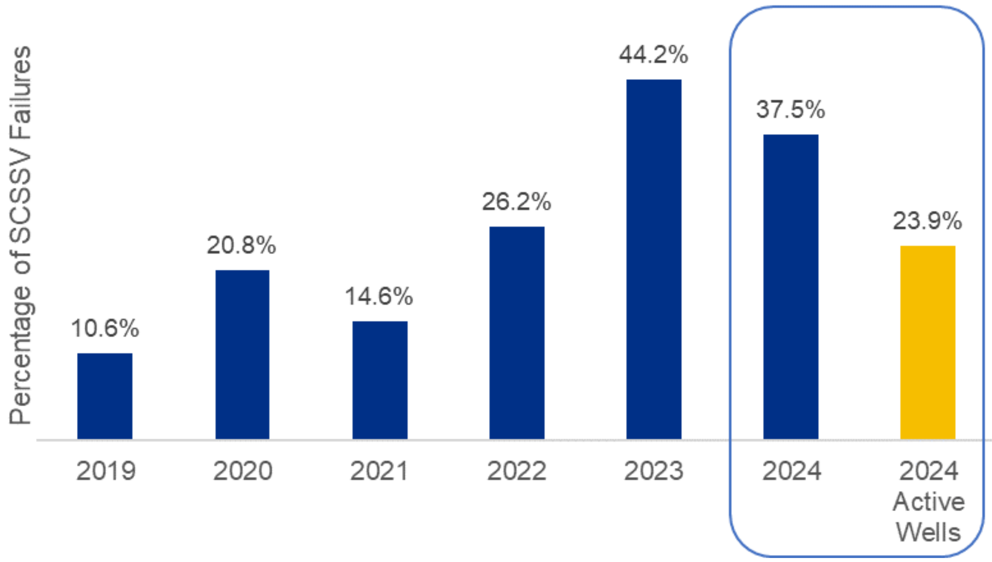


NOTE: Failures for 2019–2024 include those reported to SafeOCS and found in INCs and WAR. Failures found in APM and OGOR-A were added in 2020, and BSEE reported incident data was added in 2021.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

[23] For 2017 and 2018, BTS has not reviewed additional data sources (WAR, INC, etc.) to identify SPPE failures.
[24] Bureau of Transportation Statistics. Oil and Gas Production Safety System Events – 2023 Annual Report. Washington, D.C.: United States Department of Transportation, 2023. https://doi.org/10.21949/npq3-tr53. See page 9.

Approximately 23.2 percent of the known SCSSV failures from 2019 to 2024 occurred on deepwater wells (> 1,000 ft water depth), varying from 10.6 percent in 2019 to 44.2 percent in 2023 (Figure 10). In 2024, the percentage of SCSSV failures in deepwater exceeded the percentage of the active well population in deepwater (37.5 vs. 23.9 percent, respectively).[25]

Figure 10. SCSSV Failures in >1000 ft Water Depth, 2019–2024



NOTES: 1) Three failures with unknown water depth are excluded of 309 failures from 2019 to 2024. 2) Five wells with unknown water depth are excluded of 4,100 active wells in 2024.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS

Analyses presented in this report may consider all identified SCSSV events or a relevant subset of events. Some analyses focus on the three groups of SCSSVs with the most failure data or installations. These three groups are believed by OEMs to represent the majority of the installations in the GOA active wells today and include Groups B (concentric piston/flowtube actuated flapper), C (single control rod piston actuated flapper), and D (dual control nitrogen charged rod piston actuated flapper), which each represent multiple valve models from various OEMs.

2.1. TYPES OF FAILURE

Because subsurface safety valves are open during normal operation of production or injection wells, failures reported to SafeOCS are typically found when the operator activates (i.e., closes) the valve for required regulatory testing, typically every six months for SCSSVs.[26] These valves are rarely closed during normal operations.

Since 2017, five reported failures occurred in a situation other than routine testing or testing during a BSEE inspection. In one case, the SCSSV failed to close when commanded during normal operations. This happened on the same day that a similar valve failed to open on the same platform, so it is suspected that the operator closed the SCSSV as a precaution or to perform diagnostics after the first failure. In three cases, sandblast sand dust falsely triggered a smoke detector emergency shutdown (ESD), resulting in a platform shut-in. The SCSSVs failed

[25] Active well count and water depth were determined using OGOR-A data and BSEE boreholes data. The methodology is detailed in Appendix D of the 2023 SafeOCS SPPE Annual Report.
[26] 30 CFR 250.880(c)(1)(i) for dry trees and 30 CFR 250.880(c)(4)(i) for subsea trees.

to close due to an issue in the ESD control system. In the remaining case, a well was shut in for a hurricane evacuation and the operator was unable to confirm that the valve had closed.

2.1.1. Event Consequences

SafeOCS uses the following failure descriptions to classify an event based on its most significant consequence, because an event can have more than one outcome. The event types are listed in order of significance.

- Health, Safety, and Environment (HSE) Incident: An event with consequences that meets the thresholds described in Appendix A. For SCSSV failures, this generally involves an external leak of produced hydrocarbons to the sea of greater than one barrel.
- External Leak of Produced Hydrocarbons: An event involving an external leak of produced hydrocarbons to the sea of less than one barrel.
- Failure to Close when Commanded: The SCSSV failed to close, so it would not be effective in controlling the well flow if called upon.
- Internal Leak: The SCSSV closed but failed to seal, allowing some fluid to flow past the flapper or other closure device beyond the allowable leakage rate. SCSSVs are allowed 400 cc per minute of liquid (oil or water) or 15 scf per minute of gas.[27]
- Failure to Close in Required Timing: The SCSSV failed to close in the required time of two minutes, so it would be delayed in controlling the well flow if called upon.[28]
- Failure to Open: The SCSSV failed to open, so that well fluids could not flow through the tubing or piping, preventing production from the well. In many cases of failure to open, the valve is still capable of performing its safety function of closing to control the well flow. Because SCSSVs are normally open during production, a failure to open can only happen after a valve has been closed for planned shut-in work, closed due to an operating upset, closed for testing purposes, or closed due to an uncommanded closure.
- External Leak of Control or Other Fluids: The SCSSV allowed a loss of primary containment of fluids other than produced oil or gas, such as hydraulic fluid, while the valve can continue to operate.
- Other: This event type applies when the type of failure is known but does not fit into any of the categories above, such as unexpected pressure in the control line for an SCSSV.

Figure 11 shows the event type for 281 SCSSV failures from 2017 to 2024 where sufficient information was given to determine the type of failure. The chart includes only the highest consequence for the few failures with multiple reported types. The four failures with the highest consequence (i.e., two HSE events involving leaks to the sea and two events involving leaks of less than one barrel of hydrocarbons on the platform) were associated with SCSSVs in Group C (single control rod piston actuated flapper) and Group D (dual control nitrogen charged rod piston actuated flapper). While all four events involved leakage of produced hydrocarbons into the control system, the two HSE events that leaked to the sea occurred on subsea wells where the control lines are vented at the subsea tree by design. The other two events were leaks into the control lines on dry tree wells that led to the control fluid reservoir overflowing on the platform. The two dry tree events occurred on the same platform during the same restart after a long-term shut-in. In one case, shown as Other in Figure 11, oil reached the control fluid

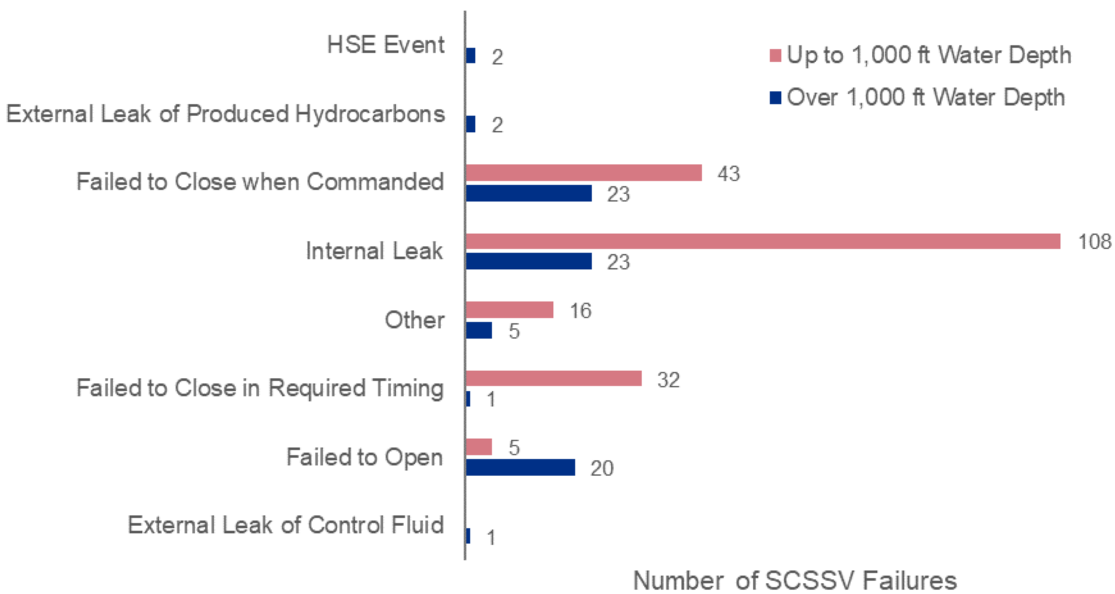
[27] 30 CFR 250.880(c)(1)(i) for dry trees and 30 CFR 250.880(c)(4)(i) for subsea trees.

[28] For dry trees, the SCSSV must close within two minutes after the ESD signal has closed the SSV for the well per 30 CFR 250.821(b). For subsea trees, the SCSSV must close in accordance with the closure times and conditions described under 30 CFR 250.838.

reservoir but did not overflow. To address the potential consequences of failures similar to the HSE incidents, and aid operators in detecting rod piston seal failures to prevent pollution events in case of seal leaks, BSEE issued Safety Alert 419.[29]

The 21 cases labeled Other consist of 15 events where pressure was found on the control line, presumably the result of leakage from the wellbore into the control line; four cases of communication between wellbore and one of the dual control lines; one uncommanded closure of the SCSSV; and one case where the control line leaked during a BSEE inspection (not specified as internal or external leak). The cases involving failure of control line communication with the wellbore and those involving pressure on the control line can be considered near misses that could have resulted in an external leak of hydrocarbons, depending on the control system configuration and the operator's responsiveness to an abnormal condition.

Figure 11. SCSSV Event Types 2017–2024



NOTE: Data includes 281 SCSSV failures where sufficient information was given to determine the type of failure.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Although listed as lower consequence, four leaks of control fluid to the sea could have been followed by leaks of hydrocarbons if they had gone unnoticed. These cases may be included in Figure 11 under a higher consequence event type, if multiple outcomes were reported. In these cases, it was determined that the rod piston seals leaked, and an operator isolated one of the redundant control lines to prevent further leakage. The SCSSV continued to operate with the remaining redundant control line.

As shown in Figure 12, internal leaks are the most common failure type for Group B (concentric piston/flowtube activated flapper) and Group C (single control rod piston actuated flapper) valves. Failures to open or close are more frequent than internal leak failures for Group D valves (dual control nitrogen charged rod piston actuated flapper), despite their redundant

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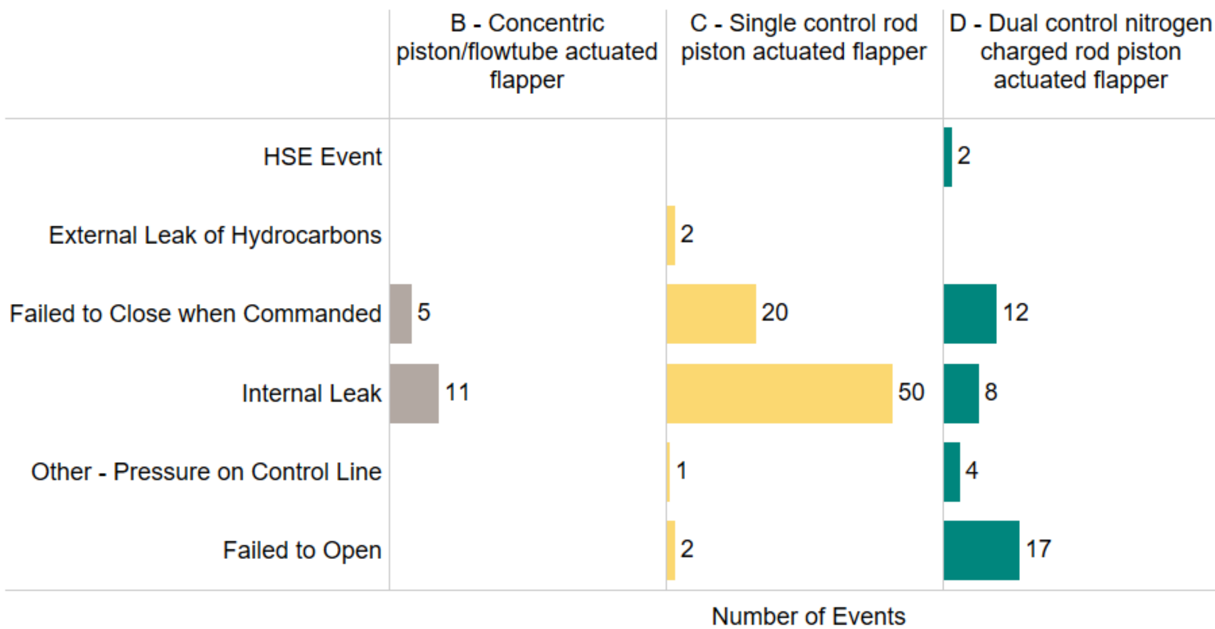
[29] BSEE Safety Alert 419 – Failed Seal on Subsea Safety Valve Causes Leak, https://www.bsee.gov/sites/bsee.gov/files/safety-alerts//bsee-safety-alert-419-failed-seal-on-subsea-safety-valve-causes-leak.pdf.

control systems. Failure to open, which is less of a safety concern than failure to close, is the most common failure type for Group D valves but was rarely reported for other valve types. In addition, failures to close exceed the number of internal leaks for Group D valves. Section 2.6 discusses possible causes and contributing factors.

Figure 12. SCSSV Event Types by Valve Design Group, 2017–2024



NOTE: Includes all 134 TR SCSSV failures for these groups where the failure type and SCSSV group type were known, except for eight that failed to close in required timing events where the ESD system was the involved component. These events are not directly attributable to the SCSSV or its dedicated control system.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

2.1.2. Valve Components

For SCSSVs, the components (parts of the valve or its control system) most often found defective or involved in reported failures include:

- Flapper, resulting in internal leakage past the flapper/seat interface.
- Valve Seat, resulting in internal leakage past the flapper/seat interface.
- Direct Hydraulic Control System, resulting in the SCSSV failing to close or open. This is the hydraulic control system that extends from the platform to the SCSSV located in the well tubing.

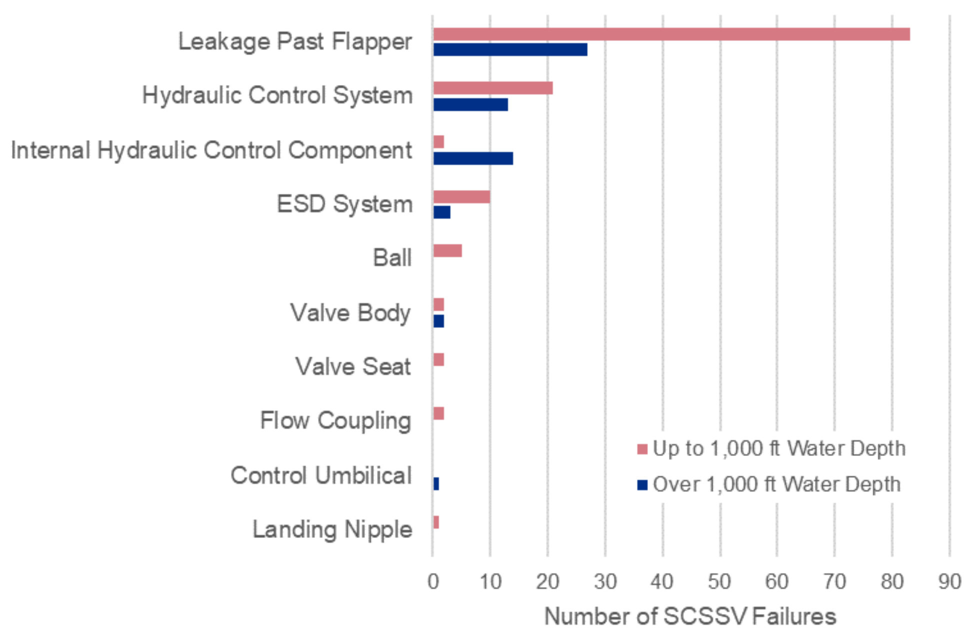
Other components that could experience a failure include:

- Ball, resulting in internal leakage past the ball. is rarely used in modern SCSSVs.
- Electro-Hydraulic Control Umbilical, usually resulting in a failure to close. This device carries electrical signals and hydraulic fluid from the platform to the wellhead of subsea wells.
- ESD System, resulting in a failure to close. This platform safety system can trigger one or more SCSSVs to close.

- Flow Coupling, resulting in internal leakage. This is a segment of tubing with heavier wall thickness typically installed above or below the well completion components, such as SCSSVs, to resist erosion where turbulence is expected.
- Landing Nipple, resulting in internal leakage. With respect to SCSSVs, the landing nipple is the top connection device designed with a specific profile to accept other components such as a plug or a WR SCSSV.
- Safety Lock. The locking mechanism that enables the TR SCSSV to be "locked open" (for example, to accept an insert WR SCSSV).
- Temperature Safety Element, resulting in inaccurate temperature measurement. Some modern SCSSVs incorporate downhole pressure and temperature sensors.
- Valve Body, resulting in internal leakage or potential external leakage. This is the outer housing of the SCSSV, which houses the actuating device (e.g., the rod piston) and the primary sealing device (e.g., the flapper).
- Other. When the subcomponent is not listed above, Other is selected and the subcomponent is described by the reporting operator. Most cases of TR SCSSVs where Other is selected involve seals in the hydraulic control portion of the SCSSV.[30]

Figure 13 shows the number of failure events from 2017 to 2024 where the failed component was identified. Most events involved leakage across the flapper, which in many cases can be addressed and returned to service, followed by a failure of the control system which is often more difficult to address.

Figure 13. Components Involved in SCSSV Failures 2017–2024



NOTE: Data includes 188 components involved in 182 SCSSV failures where the component was identified (148 TR SCSSV, 17 WR SCSSVs, and 17 SCSSVs not identified as TR or WR). More than one component can be associated with an event.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

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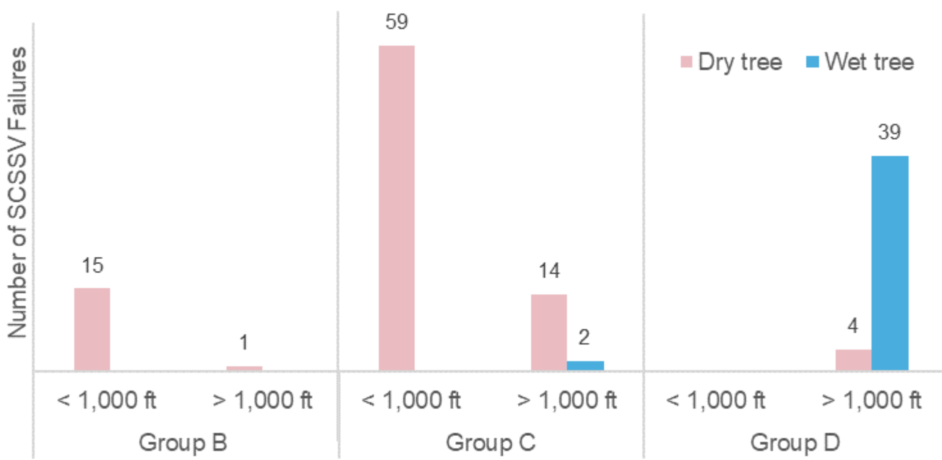
[30] BTS does not classify failures related to the actuating part of the SCSSV as "actuator" to avoid confusion with the actuator on surface safety valves.

2.2. TR SCSSV GROUPS AND WELL TYPES

When insufficient data is supplied to determine whether the SCSSV is the original TR SCSSV or an insert WR SCSSV, BTS conducted a detailed review of the WAR reports and APM submissions to determine whether a WR SCSSV has been installed. This approach assumes that all well activity, either rig activity or non-rig (wireline, coil tubing, etc.), has been recorded in WAR reports and modifications have been requested through the APM process, which should be the case. To identify as many TR SCSSV failures as practical, with a focus on deeper wells, BTS reviewed the WAR and APM data for SCSSV failures where the well was known, and the valve was installed at least 500 feet below the mean sea level. BTS confirmed 190 TR SCSSV failures, 24 WR SCSSVs failures, and 140 events where the type of SCSSV remains ambiguous. The remainder of this report focuses on the 190 TR SCSSV events.

Figure 14 describes the failures associated with each TR SCSSV group and also shows whether the well with the TR SCSSV failure was a surface well (dry tree) or a subsea well (wet tree) and whether the water depth is greater or less than 1,000 ft. Only groups B, C, and D are shown due to the limited number of failures identified on the Group A, E, and F valves. Note that most (73 of 75 failures) of Group C (single control rod piston actuated flapper) failures occurred on dry tree wells, and most (39 of 43 failures) of Group D (dual control nitrogen charged rod piston actuated flapper) failures occurred on wet tree wells. This difference corresponds to where each of these group types are installed, because Group D valves are designed to be installed at the greater depths often associated with subsea wells.

Figure 14. SCSSV Events by Tree Type and Water Depth, 2017–2024



NOTE: Includes 134 TR SCSSV failures on Group B, C, and D failures where the failure type. and water depth and tree type were known and excludes 8 events where the involved component was the ESD system. These 8 events are not directly attributable to the SCSSV or its dedicated control system.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

2.3. SCSSV SPECIFICS

2.3.1. Set Depth

In addition to the tree type (wet or dry), it is important to consider the set depth of the SCSSV. Set depth refers to the true vertical distance (TVD) down the well tubing where the safety valve is installed. Typically, SCSSVs are set deep enough to avoid hydrates and precipitation of contaminants such as paraffin. Also, BSEE requires SSSVs to be installed at least 100 ft below the mudline.[31]

The BSEE APM requires the operator to list the "SV Depth BML (ft)," or the distance of the safety valve below the mudline;[32] however, OEMs tend to refer to set depth as the distance from the top of the control line (i.e., the topside control system) to the valve location in the well tubing. They typically consider the mean sea level as the top of the control line, because the distance from mean sea level to the top of the control line is considered negligible compared to the water depth and distance the valve is set down in the well tubing. For the analysis presented in this section, set depth is the sum of the water depth and the distance from the mudline to the safety valve as reported in BSEE APM data.

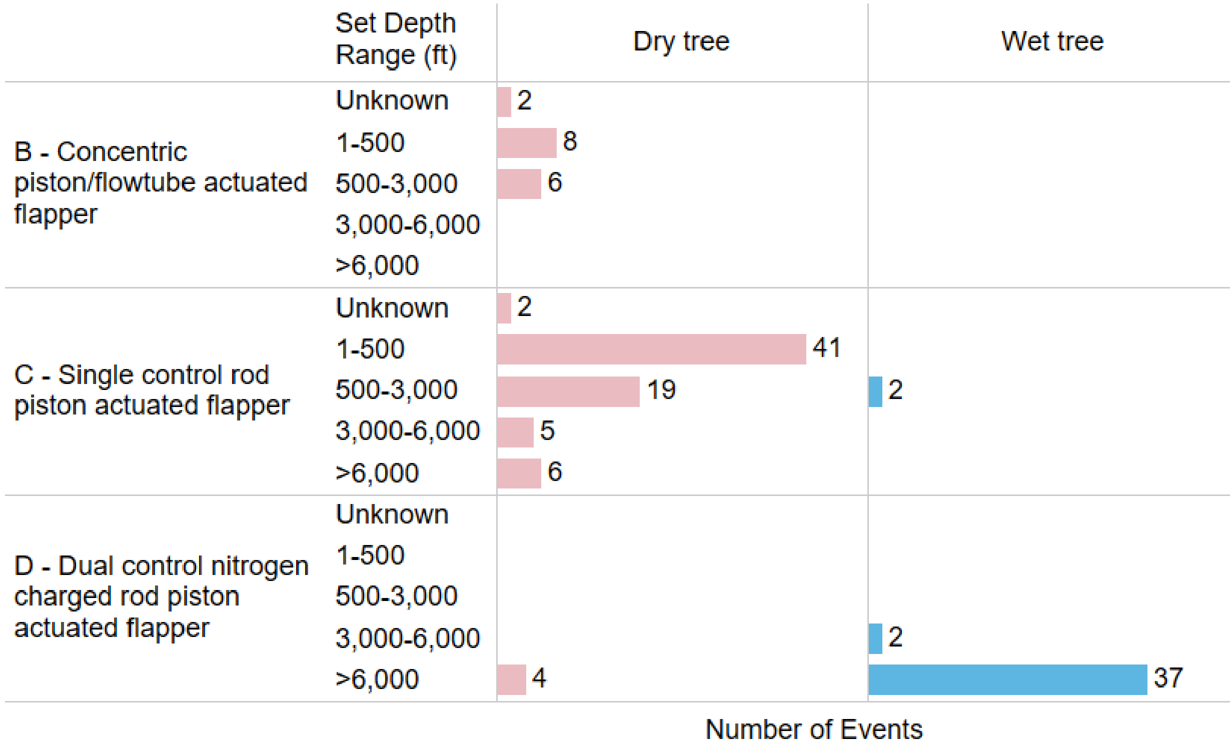
Deeper set SCSSVs will generally experience higher operating pressures and often higher operating temperatures. For many SCSSV models, set depth limits, called the "fail safe setting depth" prohibit them from being installed in subsea wells. Figure 15 shows the set depths for the SCSSVs involved in reported failure events. The set depths are grouped, with input from OEMs, as follows:

- shallow: < 500 ft
- medium: 500 to 3,000 ft
- deep: 3,000 to 6,000 ft
- ultradeep: > 6,000 ft.

As expected, Group B (concentric piston/flowtube actuated flapper) failures occurred on dry tree wells with set depths of 3,000 ft or less. Most Group C (single control rod piston actuated flapper) failures occurred at depths under 3,000 ft; however, the failure data indicates some installations failed at deeper set depths (> 6,000 ft) including two in wet tree wells. Although there have been Group D (dual control nitrogen charged rod piston actuated flapper) valves installed at lower depths, the failures indicate that these valves are used largely in > 6,000 ft set depths, and all but four of the failures occurred on wet tree wells.

[31] 30 CFR 250.814(a) and 250.828(a).
[32] See BSEE Application for Permit to Modify, Form BSEE-0124, https://www.bsee.gov/sites/bsee.gov/files/form-0124.pdf.

Figure 15. SCSSV Failures by Set Depth, 2017–2024



NOTE: Includes 134 TR SCSSV failures on Group B, C, and D failures where the failure type. and water depth and tree type were known and excludes 8 events where the involved component was the ESD system. These 8 events are not directly attributable to the SCSSV or its dedicated control system.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

2.3.2. Size, Pressure, and Temperature

The size of the valves and their pressure and temperature ratings may correlate with reliability. Pressure and temperature ratings express the capability of the valve and not its actual operating conditions. Figure 16 shows the pressure and temperature ratings for each of the SCSSV groups and the number of failures that occurred at the intersection of those two measures. The most common pressure ratings are 5,000, 10,000, and 15,000 psig, and generally the larger valves have higher ratings. Group B valves are offered only up to 3-1/2” diameter, and Group D valves are available in 3-1/2” diameter sizes and larger. One OEM noted that the failure distribution shown in Figure 16 aligns with the distribution of valve installations wherein Group B valves are generally in lower pressure (5–10k psig) and lower temperature ranges (275–300°F) and Group C valves have the broadest range of pressure and temperature ratings, but the installations are more concentrated on 5k and 10k psig pressure rating and 300°F. Group D valves have the higher pressure and temperature ratings needed for deeper subsea wells.

Figure 16. Pressure and Temperature Ratings of Failed SCSSVs, 2017–2024

SCSSV Group	Pressure Rating (psig)	Temperature Rating, F					
		250	275	300	350	400	Unknown
B - Concentric piston/flowtube actuated flapper Sizes: 2.375, 2.5, 2.875, 3.5 inches, and unknown	5k		2	7			
	5k-10k		2	1			
	10k		1				
	10k-15k						
	15k						
	15k-20k	Not available					
	20k						
	>20k						
	Unknown		1	2			
C - Single control rod piston actuated flapper Sizes 2.375, 2.875, 3.5, 4.5, 5.5 inches, and unknown	5k	1	1	27	5		3
	5k-10k		1	2			1
	10k	1		19	2		
	10k-15k					1	
	15k			3		4	1
	15k-20k					2	
	20k						
	>20k						
	Unknown				1		
D - Dual control nitrogen charged rod piston actuated flapper Sizes 3.5, 4.5, 5.5 inches, and unknown	5k						
	5k-10k			1			
	10k			15			2
	10k-15k						
	15k			14	1		
	15k-20k						
	20k					2	
	>20k			2			
	Unknown			6			

NOTE: Values represent the number of SCSSV failures with a specific pressure and temperature rating combination. Temperature ratings were assigned using the maximum temperature rating in product literature in cases where the temperature rating was not provided on the form. Includes all 134 TR SCSSV failures where the failure type and SCSSV group type were known, except eight events where the involved component was the ESD system. These events are not directly attributable to the SCSSV or its dedicated control system.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

2.4. EQUIPMENT LIFE

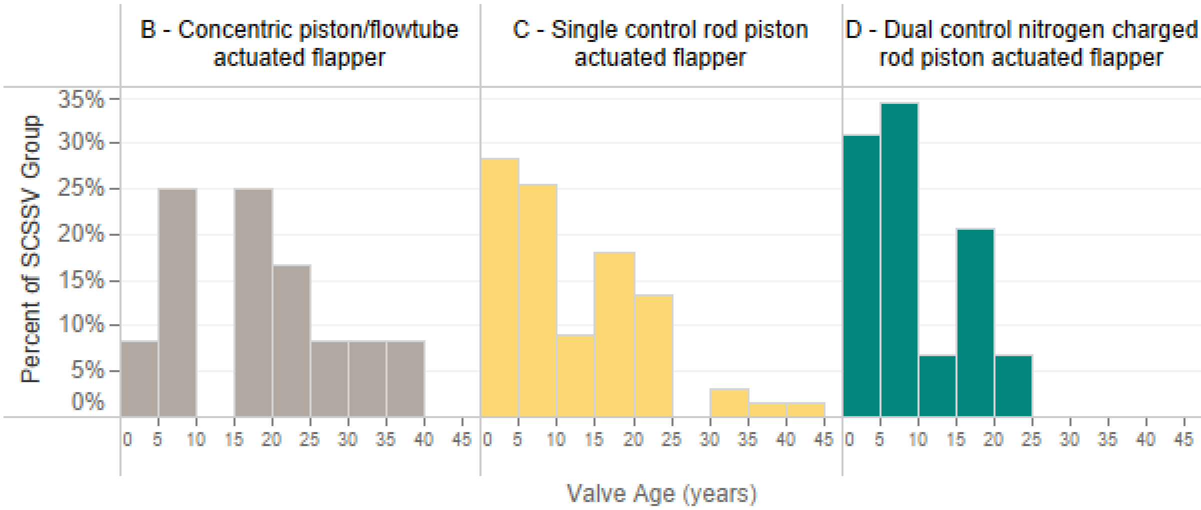
For this analysis, the age of the SCSSV at the time of failure is defined as the time from the valve's installation to the time of the failure. In cases where the installation date was not known to BTS, the well completion date was used to calculate the age, because it is unlikely that the TR SCSSV would have been replaced with another TR SCSSV since then. The last completion date for the well API number and completion interval was obtained from the BSEE API well list.[33]

Figure 17 shows the age range at the time of failure for three groups of TR SCSSV failures between 2017 and 2024. In Groups C and D, more than 30 percent of reported failures occurred within five years of installation. Examining those failures more closely, between 7 and 10 percent of reported failures occurred within one year of installation, within each SCSSV group.

[33] Bureau of Safety and Environmental Enforcement. *API Lookup*, 2025, https://www.data.bsee.gov/Well/Files/APIRawData.zip.

Notably, while Figure 17 shows that no Group D valves failed after 25 years, these valve designs were introduced in the 1990s, so there may be fewer older installations.

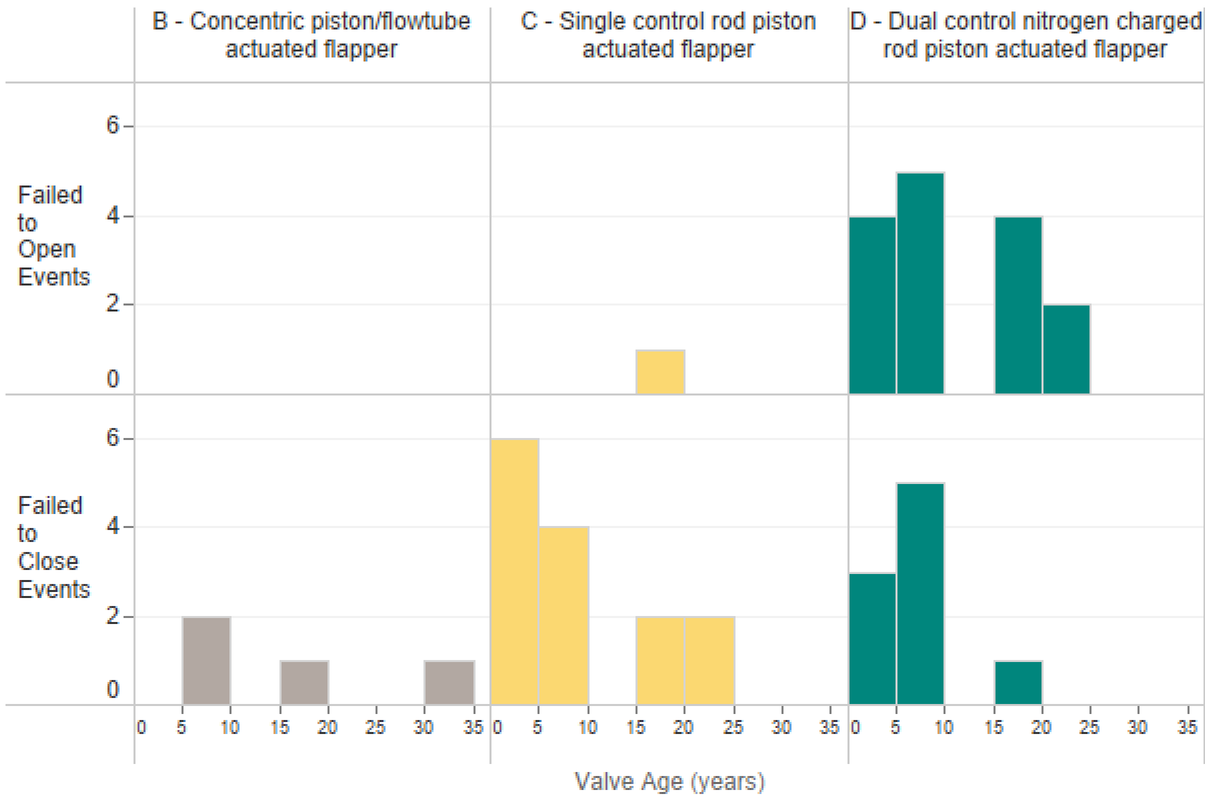
Figure 17. Events by Age of Valve, 2017–2024



NOTE: Includes 108 failures where the age of the valve could be determined, including 12 in Group B, 67 in Group C, and 29 in Group D.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Analysis of each SCSSV group shows that internal leaks (leakage past the flapper or equalization feature, if present) occur across all valve age groups. However, the failure modes that are more associated with the actuation part of the SCSSV (the rod piston and its seals, etc.), failures of the valve to open or close, may correspond to the age of Groups B and C valves. Figure 18 shows reported failures to open or close at various ages for the three SCSSV design groups B, C, and D. All three valve groups experienced failures to close in several age groups; however, all Group B failures of this type occurred after five years. This limited data set shows no failures to open for Group B valves and only one for Group C valves, which occurred later in the valve life.

Figure 18. Age of Valve When Failed to Open or Close, 2017–2024



NOTE: Includes 43 events where the age group could be determined, and the most significant failure type was that the valve failed to open or failed to close.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

2.5. WELL PRODUCTION OIL, GAS, AND WATER RATES

Production rates can offer insight into the potential environmental exposure of SCSSV failures as well as the potential impacts of operational disruptions. As shown in Figure 19, from 2017 to 2024, 19 of the reported SCSSV failures occurred on wells with higher production rates (> 5,000 barrels of oil equivalent per day or boed),[34] indicating greater potential consequences. The two HSE events previously discussed (see section 2.1.1), as well as four failures to close, occurred on wells producing more than 10,000 boed. One SCSSV failed to close three times in the same calendar year due to asphaltene buildup in and around the flapper. The presence of scale and salt was reported in the other well with a SCSSV that failed to close. This may have contributed to the failure. A third well produced approximately 6,000 boed over the 12-month period prior to its failure to close, which was also attributed to asphaltene buildup. Contaminants and other contributing factors are discussed in more detail in section 2.6.1.

Higher production rate wells are not a large portion of the active well population. In 2023, wells producing > 10,000 boed comprised 1.6 percent of all active wells in the GOA, and wells

[34] Production rates in this report are based on the average of the affected well's production rates, as reported to the Department of the Interior through OGOR-A—Oil and Gas Operations Report – Part A, over the 12-month period prior to the failure date. The average production rate in boed was the sum of each well's total produced oil volume and total gas volume (after converting to boe volume) divided by the number of days the well was in production during that period.

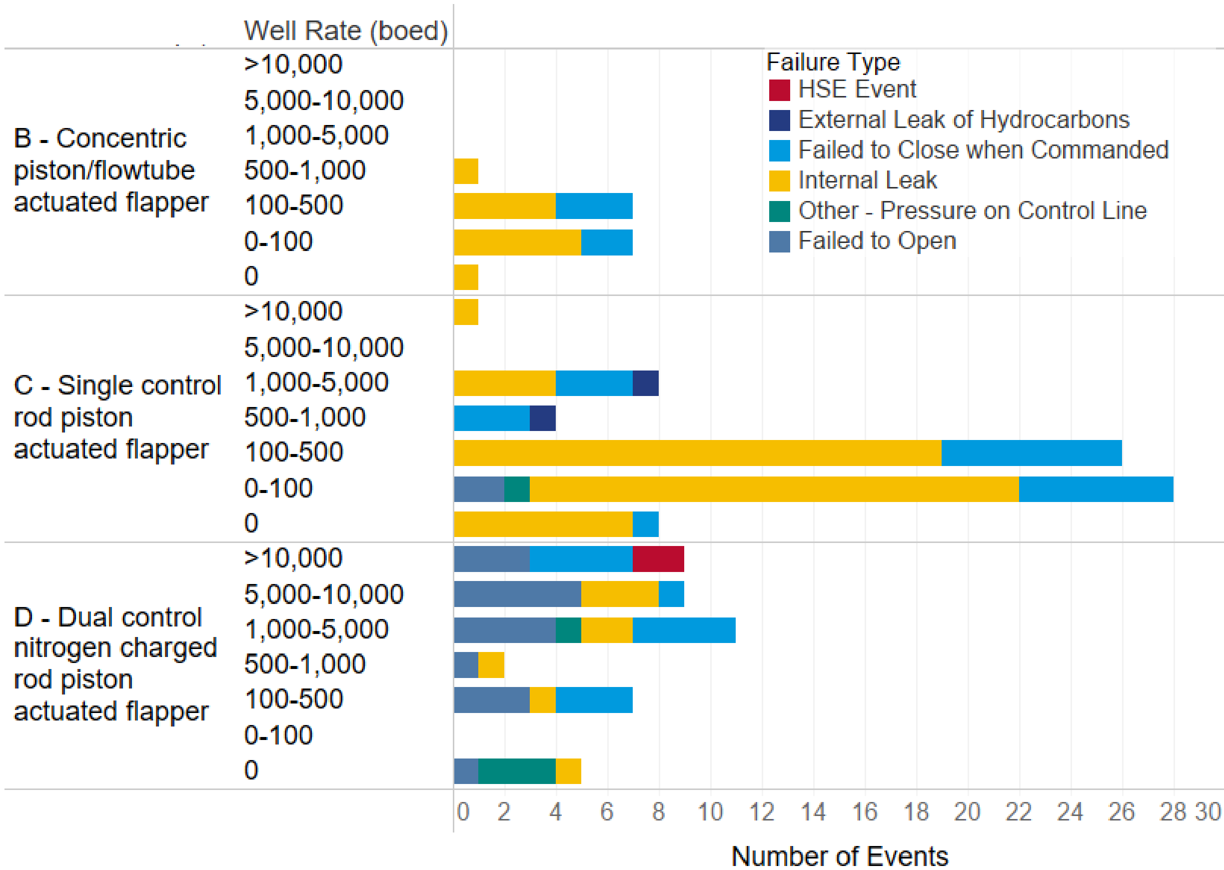
producing 5,000–10,000 boed comprised 2.4 percent.[35] This means that of the approximately 4,250 active GOA wells in 2023, approximately 170 wells that produced > 5,000 boed presented the highest risk in terms of the well rate if a failure to close occurs during an emergency.

As expected, failures on Group B valves shown in Figure 19 consists primarily of older, lower producing wells. Group C experienced internal leaks and failures to close in nearly all well rate groups, primarily in wells producing < 5,000 boed. Most failures in Group D occurred on more recent, deeper, and higher producing wells.

All but two of the failures to open occurred on Group D valves. One reason an SCSSV can fail to open is a loss of integrity (a leak) in the control line that results in placing insufficient pressure on the SCSSV rod piston so that it cannot overcome the power spring and open the valve. Another cause of a failure to open is a similar loss of pressure through the seals in the actuating part of the SCSSV. A third cause involves well production fluids and contaminants that might be present. Contaminants such as asphaltenes, paraffin, scale, sand, and wellbore debris can build up in and around the flapper and flowtube while the valve is closed for a period of time. One cannot easily distinguish between the internal seal failures and loss of integrity of the control line or umbilical, often requiring field troubleshooting which may still be inconclusive. In many cases, the operator will attempt to chemically soak and cycle or exercise the valve to restore functionality. The success of these measures would suggest that the issue is likely contaminants. In a nitrogen charged valve, nitrogen pressure counteracts the opposing control system pressure that is helping to open the valve. If the nitrogen pressure equalizes with tubing pressure through a compromised seal, the control system pressure may be insufficient to open the valve as it would have become tubing pressure sensitive.

[35] SafeOCS 2023 SPPE Annual Report, p. 23.

Figure 19. SCSSV Group and Well Rate Group, 2017–2024



NOTE: 1) Includes 134 TR SCSSV failures on Group B, C, and D failures where the failure type and well rate were known and excludes 8 events where the involved component was the ESD system. These 8 events are not directly attributable to the SCSSV or its dedicated control system. 2) The wells in the "0" well rate group include one injection well and 13 shut-in production wells.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

2.6. CAUSES AND CONTRIBUTING FACTORS

Often more than one condition or action contributes to a failure, and operators are encouraged to identify all the contributing factors in addition to the root cause of a failure. All identified contributing factors and the event type for the SCSSV failures in Groups B, C, and D are shown in Figure 20. The contributing factors are grouped by operating environment, mechanical failure and procedures. Within each group there are more specific contributing factors, as defined in the SPPE reporting guidance document.[36]

The contributing factors listed under operating environment are found in the produced fluids. These are naturally occurring substances that can be present, depending on the specific properties of the oil, gas, and water at the pressure and temperature conditions in the well especially as it flows up the well tubing to lower pressures and temperatures. For example,

[36] Bureau of Transportation Statistics. SafeOCS SPPE User Guide. Washington, D.C.: United States Department of Transportation, 2021. https://safeocs.gov/file/SPPE%20GD-9%20-%202020.02.15.pdf.

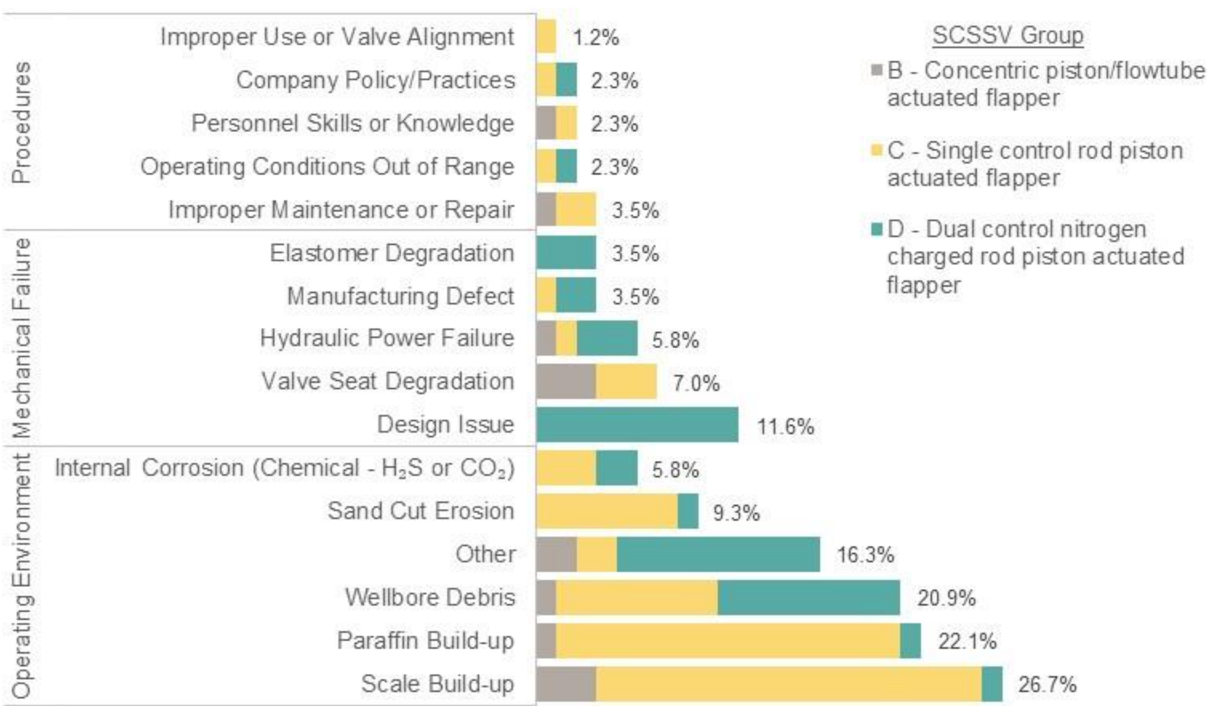
paraffin that is dissolved in the oil under reservoir conditions may deposit in the wellbore as the temperature of the oil lowers. Other chemicals, such as hydrogen sulfide or carbon dioxide, which are naturally present in some wells in varying proportions, can be corrosive.

Figure 20 shows that contaminants contributed to failures in all valve design groups. Scale is primarily listed with Group C valves, which are generally found on more mature wells with higher watercut (i.e., the volume of water produced compared to total produced fluid). Similarly, paraffin reportedly contributes primarily to failures in Group C valves. This may be due to the shallower set depths of these valves and corresponding cooler temperatures, where paraffin is more likely to precipitate than in deeper set depths. Asphaltenes (included in Other) are more commonly involved in failures of Group D valves, which also comprise all events with a Design Issue listed as a contributing factor. The design issue is related to the capability of the seals in the actuating part of the valve to withstand contaminants, which may include asphaltenes.

The contributing factors in the Mechanical Failure group can also be affected by the operating environment; however, a mechanical failure suggests that changes could be made to improve reliability despite the contaminants expected to be present. Valve seat degradation and elastomer degradation describe damage to the hardware that contributed to a resulting failure, such as a leak.

The contributing factors listed under Procedures tend to be within the operator's control. These are less commonly reported than Mechanical Failure or Operating Environment factors; however, they may present valuable lessons learned and suggest lower effort preventive measures.

Figure 20. Factors Contributing to Failure in Selected SCSSV Groups, 2017–2024



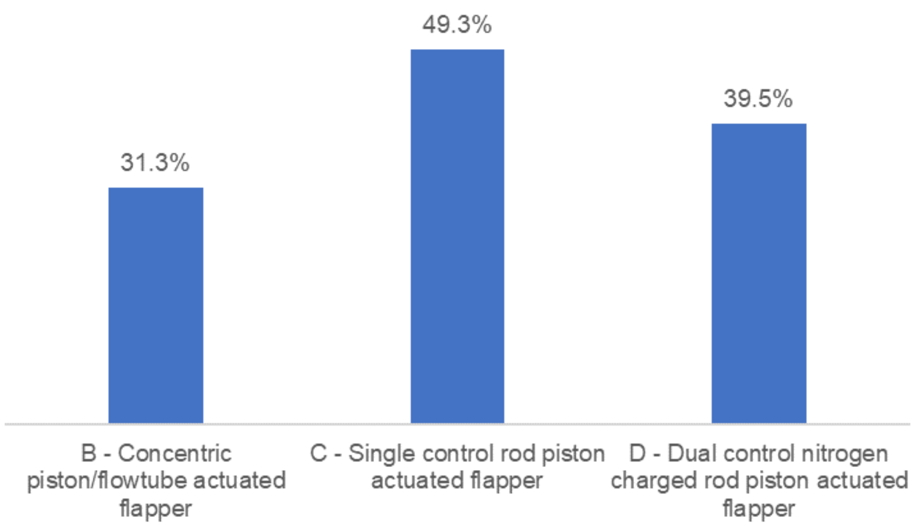
NOTE: Percentage is of 86 failures where event type was known and contributing factors were listed for Group B, C, and D valves.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

2.6.1. Operating Environment

The operating environment contributed most to the failures, with scale, paraffin, and wellbore debris each listed in more than 20 percent of the events. Solid contaminants include a broad range of specific contaminants that may be present in the well stream. These include asphaltenes, paraffin, salt, sand, scale, and other wellbore debris. The Other category primarily includes cases where asphaltenes are present, sometimes with another solid contaminant (paraffin in one case and wellbore debris in another). In addition, Other includes one case of high watercut, one mentions “trash” (debris) in the control line, and one case where the leak may have been from a gas lift valve and not attributable to the SCSSV itself.

Contaminants in the well stream can be problematic for SCSSV reliability as they can cause erosion of the flapper or seat, sticking of the flapper or flowtube, or contamination of the control system fluid. Solid contaminants contributed to 30 to 50 percent of reported failures within each SCSSV design group, as shown in Figure 21.

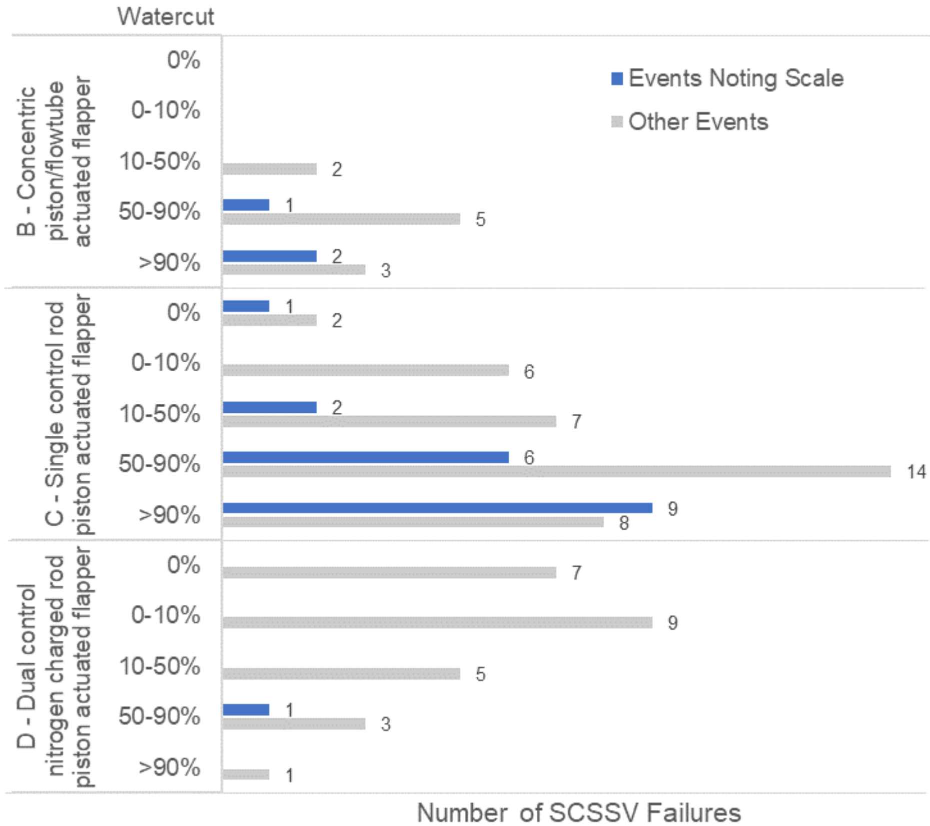
Figure 21. Events Involving Solid Contaminants by SCSSV Design Group, 2017–2024



NOTE: Includes 134 TR SCSSV failures on Group B, C, and D failures and excludes 8 events where the involved component was the ESD system. These 8 events are not directly attributable to the SCSSV or its dedicated control system. Percentage is of the failures for each SCSSV design group, including 16 in Group B, 75 in Group C and 43 in Group D.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Scale (typically calcium carbonate) is the most common wellbore contaminant that contributed to reported SCSSV failures. It is most often present when watercut exceeds 50 percent. Figure 22 shows the watercut for failures involving scale in each valve design group. In Group C valves, one of the three events that occurred on gas wells with zero watercut experienced scale. In Group D valves, seven events occurred on oil wells with zero watercut did not experience scale. These were oil wells that were not producing water. In addition to the failures that listed scale as a contributing factor, six failures included scale as an environmental condition, all on wells with more than 50 percent watercut. Four of these failures occurred on wells with Group C SCSSVs, one on a well with a Group B SCSSV and one on a well with a Group D SCSSV.

Figure 22. Watercut for Failures Involving Scale, 2017–2024



NOTE: Data includes 94 failures of Groups B (13), C (55), and D (26) valves in wells that produced during the 12 months prior to the failure. Events occurring on injection wells or wells with no production during the 12 months prior to the failure are excluded.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

The wellbore debris category is intended to exclude other contaminants like asphaltenes, paraffin and sand; however, it is possible that data submitters selected it as a catchall when the specific contaminant was not known. “Wellbore debris” could also refer to debris in the reservoir near the well completion that is the result of drilling and completing the well, including proppant and precipitates that may have resulted from acid stimulations.

2.6.2. Mechanical Failure

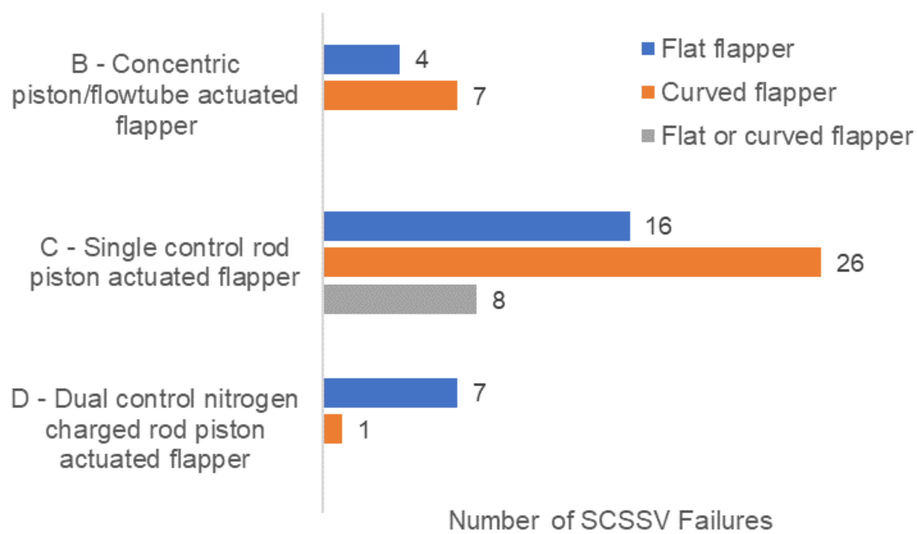
Design issues, manufacturing defects, and specific part failures are grouped under Mechanical Failure in Figure 20. This figure indicates that design issues contributed to 11.6 percent of the failures where contributing factors were reported. During the period studied in this report, design issues related to the seals in the actuating portion of the valve were identified and addressed, described further in section 2.6.4. Other design considerations that may contribute to failures include the flapper shape and the equalization feature, if present.

There is debate about whether a curved flapper or a flat flapper is more likely to leak over time.[37] Flapper designs have been improved so that they resist potential damage caused by other well work, such as wireline operations where the wireline passes through the open SCSSV and the SCSSV could unintentionally close on the wire. However, it is difficult to draw conclusions without more precise information about the populations of flat and curved flappers in use under similar operating conditions and environments. Thus, the following analysis should be viewed as exploratory.

The event type most likely to involve the flapper shape is an internal leak. Figure 23 shows the flapper type involved in the internal leak failures in SCSSV Groups B, C and D. Flat and curved (or contoured) flappers are available for models in each SCSSV group. Based on the model information provided by the OEMs, BTS was able to determine whether a flat flapper or curved flapper was involved in an event except in eight cases which are shown as “flat or curved flapper”. More failures occurred among Group D valves that had flat flappers than in those with curved flappers, which aligns with information from the OEMs indicating that most installed Group D valves have flat flappers. More data would be needed to evaluate the importance of flapper shape in a valve’s capability to pass a leakage test compared to other contributing factors.

BTS also reviewed the same set of failures involving internal leakage to assess the contribution of self-equalizing features. However, the use of non-equalizing or self-equalizing valves was available for fewer than 20 cases, so this data is not presented. If this is an area of further interest to industry, BTS is able to perform a supplemental evaluation given additional information from the OEM on the specific serial numbers of the SCSSVs involved and the operator’s permission for BTS to share failure data with the OEMs.

Figure 23. Type of Flapper Involved in Internal Leak Events, 2017–2024



NOTE: Data includes 69 events where the model and SCSSV design group were known, and the event involved an internal leak past a closed flapper.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Other factors that could contribute to Mechanical Failure such as valve seat degradation and elastomer degradation are rarely noted because the resulting SCSSV failures are often resolved

[37] Based on discussions with OEM representatives.

by cleaning and exercising the valve. However, the few cases where the valve was retrieved and replaced present opportunities to observe the internal condition of the valve after its time in service.

Three of the five events noting hydraulic power failure were further described. The failure was described as physical damage to the control line in one case and suspected blockage in the control line in the two other cases. The damaged control line was corrected by installing an SSCSV. In one case the operator was able to cycle the valve to resume operations, and in another case an insert SCSSV was installed.

2.6.3. Procedures

Operating conditions, such as control system pressure, are not captured on the SafeOCS data collection form; however, some reports cited operating conditions out of range as a contributing factor. These reports did not provide further detail. In discussions with BTS, one OEM representative offered an example of a failure that occurred because operating conditions were out of range. In this example, an accelerated failure of the piston seals occurs if the control pressure is not operated at a sufficient pressure to hold the valve fully open. If the piston rod seals are allowed to “chatter” in that condition, they could effectively cycle a more rapidly than expected for the minimum design life of 500 cycles, where the valve is typically only cycled in emergencies or for testing every six months.[38]

Three events noted “improper maintenance or repair” along with either scale or paraffin. In these cases, the valve performance was restored by wireline scratching and exercising the valve, suggesting that increasing the frequency of these activities may reduce the likelihood of failure.

Although not specifically described in any failure reports, abnormal operating conditions such as those encountered during a chemical soaking operation can also contribute to valve failures. Sudden changes in temperature can occur when relatively cold soaking fluids are introduced to the warm wellbore temperatures at the SCSSV. Then, if the temperature is not allowed to stabilize before the warm well fluids are introduced, a sudden increase in temperature could also occur.

2.6.4. Root Cause

The root cause field is meant to capture the primary underlying factor leading to the event. As shown in Figure 24, about one third of TR SCSSV failures were reported with an Unknown root cause because limited diagnostics or failure analysis can be conducted if the SCSSV is not retrieved from the well. Wear and Tear is listed as the root cause more commonly for Group B and C valves but is surpassed by Maintenance Plan and Procedure as well as Design Issue for Group D valves. Wear and Tear was reported as the root cause for 11 of the 29 events where the valve age was known and less than five years. Three of the 11 failures occurred on the same valve approximately six months apart. That well was originally completed in 1994, and it is possible that the original valve had been in service more than 24 years and encountered two recompletions through it before an insert valve was installed. The well was abandoned in 2022. Two other wells of the 11 Wear and Tear events had original completion dates more than 20

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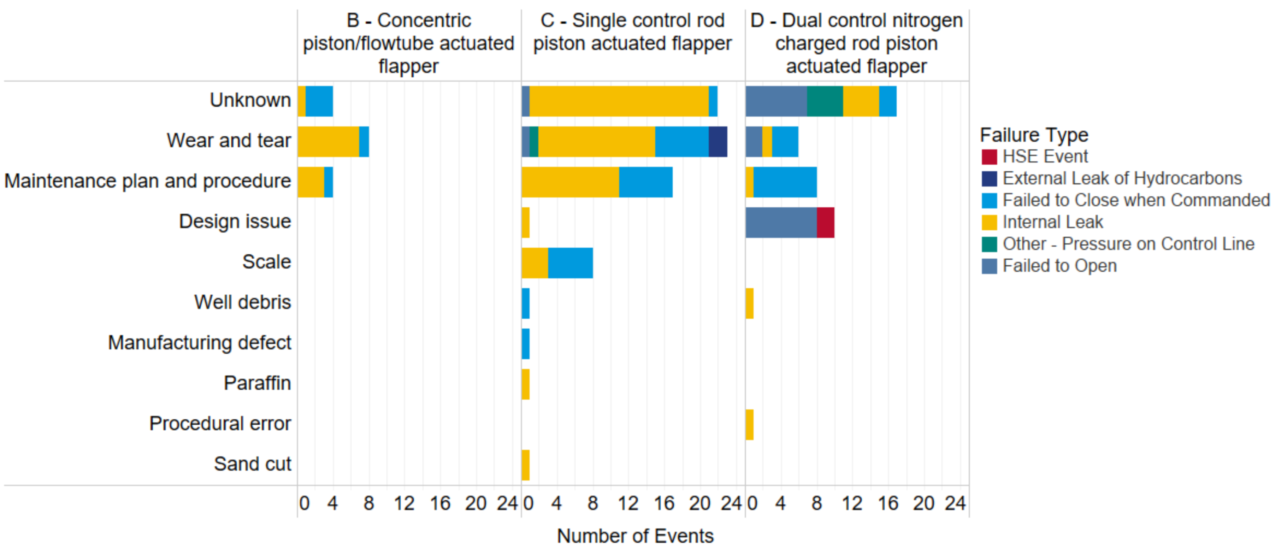
[38] API SPEC 14A, Section G.3.1.2 states “The number of cycles defining operating life expectations shall be a minimum of 500 operating cycles, or more if specified by the user/purchaser.”

years prior to the failure, three failures occurred between nine and 13 years prior, and three were less than five years prior.

The failures in Group D that cite Design Issue as the root cause have been linked to rod piston seal failures in the actuating section of the SCSSV, and at least one OEM notes that sealing nitrogen with a dynamic seal (i.e., one that seals parts that change position as opposed to a static seal that seals stationary parts) is challenging in the long term (i.e., more than 20 years expected life). These issues and other improvements are being addressed with design changes and introduction of new SCSSV models to improve valve reliability.

Figure 24. Root Causes of SCSSV Failures, 2017–2024



NOTE: Includes 134 TR SCSSV failures on Group B, C, and D failures where the failure type was known and excludes 8 events where the involved component was the ESD system. These 8 events are not directly attributable to the SCSSV or its dedicated control system.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

2.6.5. Corrective Actions

How do operators combat these challenging operating environments? When the exact contaminant is known, the proper chemical treatment can be applied. Samples of reservoir fluids taken during the exploration phase are analyzed to predict the likelihood of specific contaminants. When expected, certain contaminants can be addressed with continuous chemical injection (e.g., paraffin inhibitor) or periodic chemical treatments (e.g., scale squeeze). Of course, unexpected contaminants can occur later in the life of the well.

Figure 25 conveys the corrective actions taken to address reported failures. In cases involving multiple corrective actions, only the most significant corrective action is shown. Brief explanations of the corrective actions are provided below in order of significance.

- Modify Well – A change was made to the well barrier configuration, such as:

- Installed plug - installed a plug in the well to ensure flow is blocked until the valve issue can be addressed or until the well is abandoned in cases where no other solution is viable.
  - Installed SSCSV – Installed a subsurface controlled subsurface safety valve (SSCSV) to continue operations.
  - Recompleted well – The well was recompleted, typically including restoring the SCSSV to new condition.
  - Abandoned well – The well was permanently abandoned.
- Modify SPPE – A change was made to the valve, such as:
  - Different model TR SCSSV – Replaced the SCSSV with a different model.
  - Installed insert - Installed an insert or WR SCSSV.
- 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. Note: to avoid production deferment there would typically be a new SCSSV purchased and ready to install rather than waiting for the original valve to be sent for remanufacturing or repair. These cases would be classified as Replace.
- Chemical Soak – A chemical solvent was introduced to the valve to dissolve buildups of contaminants such as scale or asphaltenes.
- Repair – The valve was repaired, or part of the valve (a component) was replaced. This could also be a repair of the control line.
- 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. Exercising the valve means cycling it multiple times.

The most common action is shutting in the well for more than 30 days, especially where a subsea well is involved as an intervention vessel may be needed to address the failure. Typically, another action is needed to address the failure. Rather than showing the three events where “shut in well” was the only known action, they are included in the Unknown category in Figure 25 because it is not known what other action was taken.

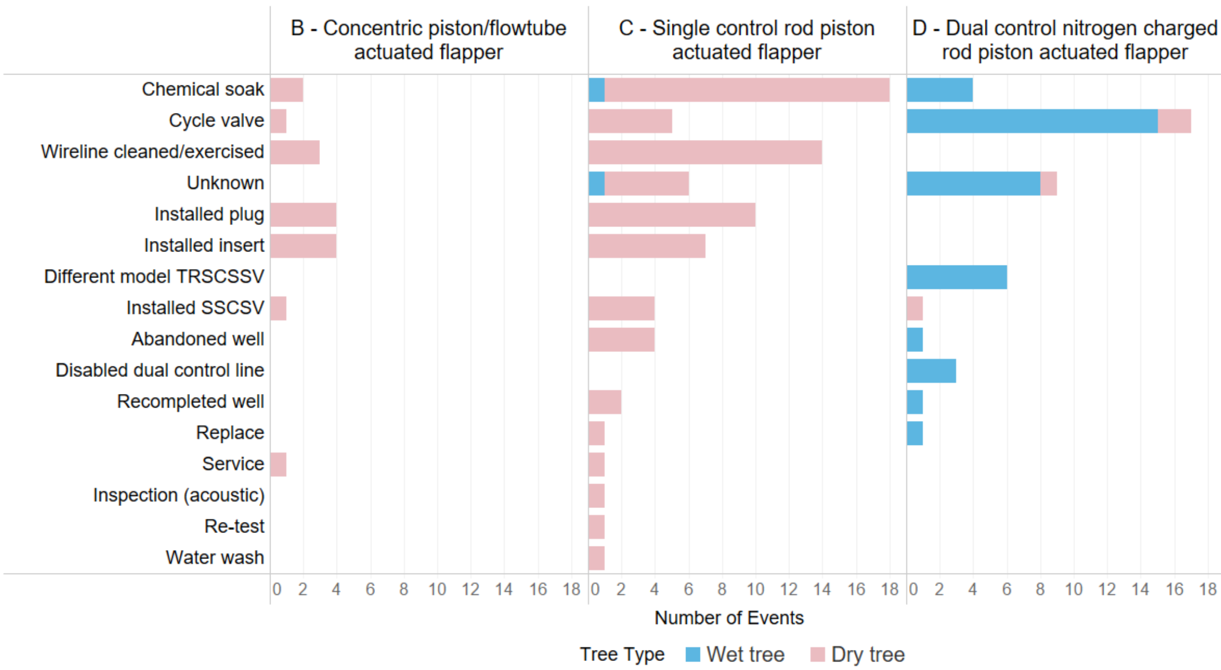
Another common corrective action is to chemically soak the wellbore and SCSSV. Xylene, hydrochloric acid, or another solvent may be pumped into the well and allowed to soak and dissolve contaminants. In many cases, exercising the valve is reported in addition to the chemical soak. Although opinions vary about the effectiveness of mechanical cleaning tools compared to chemical cleaning, the “Other” category includes 20 events where a wireline scratching tool was used to clean the SCSSV (15) or perform some other wireline activity (2), the valve was inspected using an acoustic survey (1), water washing the valve (1), or simply retesting the valve (1).

More drastic corrective actions for TR SCSSVs include replacing the valve, which has rarely been performed. When a failure occurs, operators will typically attempt to restore safe production using lower cost alternatives, as removing the valve requires a rig workover which involves cost factors that can preclude further profitable production of the well.[39] In the small number of cases where the tubing was pulled and the TR SCSSV was replaced, a different

[39] Cost factors associated with intervention, maintenance, and repair of deepwater production systems are discussed in: Goldsmith, Riley, Remi Eriksen, Matthew Childs, Brian Saucier, and F. Jonathan Deegan. “Lifecycle Cost of Deepwater Production Systems.” Offshore Technology Conference, 2001. https://doi.org/10.4043/12941-MS.

model SCSSV was installed. These are included in Figure 25 as “different model TR SCSSV” (to distinguish them from “Replace” where the valve is replaced in kind) for either dry tree wells or wet tree wells. In dry tree wells, a wireline retrievable insert SCSSV can also be installed in the nipple profile of the TR SCSSV as an alternative to replacement.

Figure 25. Corrective Actions to Address SCSSV Failures, 2017–2024



NOTE: Includes 134 TR SCSSV failures on Group B, C, and D failures where the failure type was known and excludes 8 events where the involved component was the ESD system. These 8 events are not directly attributable to the SCSSV or its dedicated control system.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

2.7. REPEAT FAILURE DETAILS

Repeat failures of the same valve can occur if the root cause is not sufficiently addressed. In the B, C and D SCSSV design groups, nine failures occurred within 12 months of a previous failure of the same valve. This includes five repeat failures in Group C and four in Group D valves. These failures were either internal leaks (failing the leakage rate test) or failures to close.

Four (of five) of the reported repeat failures for Group C valves were internal leaks. Related descriptions of the contaminants or corrective action suggest that all the repeat failures were related to contaminants and in most cases were resolved by cycling or chemical treatments. In one case, however, after the first failure was resolved with chemical soaking, the failure reoccurred, and an insert valve (WR SCSSV) was installed. Group C repeat events involved low production wells with high watercut.

The four repeat failures within Group D occurred on three wells with higher production rates and lower watercut (< 10 percent). In one case, the valve failed to close when cycled after returning to the platform from a hurricane evacuation. The well did return to production, but the corrective action was not reported to BTS. Two of the four repeat failures occurred on the same SCSSV, which was on a well with asphaltene contaminants present. After chemically soaking the valve to remedy the first failure, another occurred after approximately seven months, and cycling the valve restored its functionality. However, it failed to close again the next month. The final repeat Group D failure was an internal leak of unknown cause, and the earlier failure was due to a procedural error in the testing itself. Cycling the valve and retesting resolved the issue.

3. Conclusions and Information Sharing

3.1. CONCLUSIONS

Hundreds of valves like those discussed in this report operate in active wells in the GOA. Although the industry has implemented design improvements, including to address failures of rod piston seals in nitrogen-charged SCSSVs where contaminants contributed to the failure, valves currently in operation may be at risk of similar failures. Although lack of economic feasibility hinders replacement of all existing valves of this design, industry can mitigate the risk of hydrocarbon leaks to the sea through improved operational surveillance. Deferred production remains a foreseeable risk when an SCSSV fails to open.

A standard industrywide definition of a failure, including examples explaining what should be reported, could improve data collection completeness and data quality. This change could improve industry understanding of what event details should be reported, promoting improved awareness and faster development of preventive actions for an emerging issue.

Information about failures and operating history, especially recent well maintenance or operating upsets, can be helpful in root cause analysis efforts. BTS welcomes input on the data collection form that might help improve the compilation of this information.

3.2. INFORMATION SHARING OPPORTUNITIES

The information in this report is intended to enable OEMs and operators to better understand the challenges of operating and maintaining SCSSVs in the GOA well environment without identifying specific SCSSV models. However, as details are crucial to any in-depth investigation and failure analysis, BTS invites OEMs to request specific data needed for product improvements. Operators should also provide their failure data to the appropriate OEM; however, BTS may have a more complete set of data covering all operators and more than eight years of failure information.

In many cases, BTS may not have received all the follow-up failure analysis reports, especially those identified by BTS in reviews of other data sources (INC, WAR, APM, OGOR-A, etc.). To compile a more meaningful and complete data set from which to learn, BTS encourages both OEMs and operators to submit investigation reports and any other relevant documentation to BTS confidentially under the CIPSEA protections afforded by the SafeOCS program.

If you have questions about how to share information with BTS, please contact the SafeOCS team by emailing SafeOCS@dot.gov.

Appendix A. HSE Incidents

A health, safety, and environment (HSE) incident can generally be defined as an event that results in consequences to health, safety or the environment. For purposes of this report, an HSE incident is an event that results in consequences to health, safety, or the environment above a specified threshold, as detailed below. See also BSEE HSE incident reporting requirements at 30 CFR 250.188, 30 CFR 254.46, and NTL No. 2019-N05.

- One or more fatalities
- Injury to five 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 or 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 results in process or equipment shutdown
- Muster for evacuation
- Structural damage
- Spill > one barrel