WELL CONTROL EQUIPMENT SYSTEMS SAFETY

2022 ANNUAL REPORT

SafeOCS

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

Bureau of Transportation Statistics

WELL CONTROL EQUIPMENT SYSTEMS SAFETY

2022 Annual Report

ACKNOWLEDGEMENTS

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Recommended Citation:

Bureau of Transportation Statistics. *Well Control Equipment Systems Safety – 2022 Annual Report.* Washington, D.C.: United States Department of Transportation, 2022.
https://doi.org/10.21949/1528705

Cover photographs by Tony Hogg.

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Executive Summary

The *Well Control Equipment Systems Safety – 2022 Annual Report*, produced by the Bureau of Transportation Statistics, summarizes well control equipment (WCE) failure events that occurred during well operations in the Gulf of Mexico (GOM) Outer Continental Shelf (OCS) from 2017 to 2022. This report is based on information collected through SafeOCS, a confidential reporting program for the collection and analysis of data to advance safety in offshore energy operations. It contains an analysis of reported events involving WCE systems, including blowout preventer (BOP) equipment, and other key information about the events such as root causes and follow-up actions.

SafeOCS received event reports for 5,130 WCE events from 2017 to 2022, averaging 855 events per year. Most of these events (86.7 percent) occurred while not in operation, i.e., during maintenance, inspection, and testing. Reported events declined each year, reaching an annual low of 411 events in 2021, and increasing by 17.0 percent to 481 in 2022. Well activity levels, as measured by BOP days (meaning the number of days during which WCE systems were in use) showed a similar pattern, reaching an annual low in 2021, with an increase of 10.5 percent in 2022. Marked declines in several measures of well operations activity (wells spudded, active rig count, and BOP days) coincided with the onset of the COVID-19 pandemic in the second quarter of 2020. Some of these measures have seen an increase in the last two years, while others have mostly stabilized, with some steadily increasing and then decreasing again in the second half of 2022. Adjusting for well operations activity (as measured by BOP days), the rate of reported events reached an annual low in 2021 of 36.8 events per thousand BOP days and increased slightly in 2022 to 38.9. Only one reported event from 2017 to 2022 resulted in a loss of containment of more than a barrel of wellbore fluids to the environment.

Subsea WCE System Events

Subsea WCE system events comprised 92.7 percent of failure events from 2017 to 2022, and subsea BOP days represented 63.9 percent of all BOP days. Over the six-year period, regulators, solenoid valves (hydraulic), SPM valves, slide (shear-seal) valves, shuttle valves, and piping/tubing were among the most frequently reported components, each representing at least

5.0 percent of all subsea system failures. Most events were classified as external leaks, none of which were leaks of wellbore fluids. The most common root causes were wear and tear (reported for 46.6 percent of events from 2017 to 2022), design issue (15.2 percent), and maintenance error (12.3 percent). Forty events over the six-year period resulted in BOP stack pulls associated with various component types. Piping/tubing was associated with the most (seven) BOP stack pulls, followed by annular packing elements (four), ram block seals (four), and SPM valves (three). Operating system seals and flex loop hose were each associated with two BOP stack pulls since 2017.

Surface WCE System Events

Surface WCE system events comprised 7.3 percent of failure events from 2017 to 2022, and surface BOP days represented 36.2 percent of all BOP days. Over the six-year period, annular packing elements, accumulators, ram block seals, gate valve hardware, choke and kill valves, general hardware, and regulators were among the most frequently reported components, each representing at least 5.0 percent of all surface system failures. Internal leaks were the most common failure type (47.0 percent of events), and wear and tear (61.2 percent of events) was the most common root cause. Ninety-six events over the six-year period resulted in BOP stack pulls, with 51.0 percent associated with an internal leak across the annular packing element.

Introduction

The *2022 Annual Report: Well Control Equipment Systems Safety*, produced by the Bureau of Transportation Statistics (BTS), provides information on well control equipment (WCE) failures reported to SafeOCS from 2017 to 2022. These failures occurred during well operations in the Gulf of Mexico (GOM) Outer Continental Shelf (OCS). Per 30 CFR 250.730(c), operators must report any equipment failures experienced during these activities to SafeOCS (see Appendix A).

About SafeOCS

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

The SafeOCS program umbrella comprises several safety data collections, including the WCE failure reporting program, which is the subject of this report. The WCE program includes reports of well control equipment failure events mandated under 30 CFR 250.730(c). This regulation requires operators to follow the failure reporting procedures in API Standard 53 (4th ed.), submit failure reports to BTS as BSEE's designated third party to receive this information, and submit failure reports to the original equipment manufacturer. The WCE failure reporting program began in 2016 and this is the seventh annual report.[2]

[1] Confidential Information Protection and Statistical Efficiency Act of 2018, Pub. L. No. 115-435, tit. III (reauthorizing the 2002 law of the same name).

[2] Prior to 2019, the annual reports were titled *Blowout Prevention System Safety Events*.

Stakeholder Collaboration

This annual report is the product of a wide-ranging collaboration between key stakeholders in the oil and gas industry and government. They include the following:

- **The Joint Industry Project on Blowout Preventer Reliability Data (BOP Reliability JIP)**: The SafeOCS program continues to receive input from the JIP, a collaboration between the International Association of Drilling Contractors (IADC) and the International Association of Oil and Gas Producers (IOGP). The JIP developed and manages RAPID-S53, the Reliability and Performance Information Database for Well Control Equipment covered under API Standard 53.
- **Internal Review Team**: SafeOCS retained experts in drilling operations, production operations, equipment testing, and well control equipment design and manufacturing. The subject matter experts reviewed event reports, validated and clarified BTS and BSEE data, and provided input to this report. These subject matter experts interpret the written reports supplied to SafeOCS, but they are not involved in any physical analysis or interviews with those involved in equipment failures. Clarifications on events are provided from operators on an as needed basis.
- **BSEE**: BSEE provided BTS with well-related data used for data validation, benchmarking, and development of exposure measures, described under Data Validation and Exposure Measures (page 4).

Context for WCE Events

WCE systems, including BOP equipment, control the flow of formation and other fluids during oil and gas well operations.[3] This report focuses on events that occurred while maintaining, inspecting, testing, and operating WCE systems during offshore well operations. To understand when and how WCE is used, it is important to recognize that drilling operations encompass more than the act of drilling, and include all activities related to constructing an oil or gas well. For example, in addition to drilling the hole (wellbore) to the correct size and depth, well construction includes preventing the hole from collapsing and maintaining pressure integrity

[3] Well operations include drilling, completion, workover, and decommissioning activities. 30 CFR 250.700.

within the hole. This process involves running lengths of various size pipes (conductor, casing, or tubing) into the wellbore, cementing them in place to isolate any potential flow zone,[4] and preparing the well for subsequent production operations.

WCE systems are critical to ensuring the safety of personnel and the environment during drilling and other well operations. WCE, for purposes of this report, is broken down into the following system subunits:

- BOP stack
- BOP controls
- Riser
- Diverter
- Choke manifold
- Auxiliary equipment

Of these, the BOP controls and the BOP stack systems, both of which comprise thousands of components and consume the most hours of maintenance of any system on the rig, are among the most important for safeguarding against adverse events. Normally, the BOP control systems and BOP stack systems are on standby, ready to respond to a well control event. Operators are required to conduct and meet API Standard 53 (4th ed.) testing criteria at various times during well operations to ensure these systems will function as expected if needed. WCE systems must be maintained and inspected before tests can be carried out and then tested again at predetermined intervals per requirements. This cycle of maintenance, inspection, and testing is further discussed in Appendix B.

This report contains a chapter about subsea WCE systems, followed by a chapter on surface WCE systems. Differences between events that occurred while in operation versus not in operation (i.e., during maintenance, inspection, and testing) are noted where relevant. In-operation events are further evaluated as to whether they led to a BOP stack pull. The following factors were considered in determining how to present the data:

- **WCE System Complexity**: Subsea WCE systems have a much higher population of components than surface WCE systems. This is due to complexity caused by the distance between the BOP stack and the rig-mounted control panels and redundancies intended to prevent single-point failures while inaccessible equipment is in use.

[4] Any zone in a well where flow is possible under conditions when wellbore pressure is less than pore pressure.

- **Accessibility of Equipment**: Most subsea system equipment is underwater and limited to observation and simple operations by a remotely operated vehicle (ROV),[5] whereas surface system equipment is always visible and accessible by the rig crew.[6]
- **Management of Equipment**: Rigs with subsea BOPs have full-time crews of dedicated subsea engineers that install and maintain the WCE. Surface BOP systems are typically operated by the drill crews and maintained by the rig mechanic, in addition to their standard duties. These crew differences lead to different operational and reporting practices for subsea systems as compared to surface systems. For example, for surface systems, WCE components are often sent to shore for major maintenance, whereas most of these activities are typically conducted onsite for subsea systems (unless OEM maintenance agreements require a return to base).
- **Risk:** Events that occur when the system is not in operation present fewer potential consequences than events that occur when the system is in operation, since not-in-operation events can be corrected before operations begin. Importantly, most in-operation events do not result in consequences because of equipment redundancy and the relatively short period that well pressures can lead to a blowout.[7] Understanding what components fail while in operation, as well as how, when, and why they fail, is critical to reduce or eliminate similar events in the future.

Data Validation and Exposure Measures

BTS used data provided by BSEE to validate SafeOCS data and develop exposure measures that help provide context for the failures. BTS validated submitted data by reviewing well activity reports (WARs), which oil and gas operators must submit to BSEE weekly for active well

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[5] An ROV is required under 30 CFR 250.734 and provides a live video feed together with the capability to open and close specific control valves and perform some other simple tasks.

[6] On a subsea system, the BOP stack, the BOP control pods, hoses, cables, and the marine drilling riser are all located underwater when in use and are therefore inaccessible. The subsea BOP stack equipment is densely packed into a handling and protection frame, making access difficult and time-consuming. All the equivalent equipment on a surface system is above water and joined together using industry-standard connections, making access easier.

[7] A well can experience a blowout when the formation's pressure is higher than the drilling fluid's hydrostatic pressure.

operations in the Gulf of Mexico OCS Region, per 30 CFR 250.743. WARs were also used to identify WCE failure events that were not reported to SafeOCS.

BTS also used BSEE data sources, including WARs, to develop exposure measures that quantify the population of equipment subject to failure and its characteristics. These exposure measures, sometimes referred to as denominator or normalizing data because they represent the population based on statistical values, facilitate comparisons over time and between different types of WCE. WAR data is used to develop several measures (numbered one through seven below) that approximate the number of active operators and the amount of rig activity.[8] An additional measure, wells spudded (number eight below), is developed from the BSEE boreholes table and provides information on the extent of new well activity. The measures include the following:

1. **Active operators**: The number of operators conducting rig operations.
2. **Wells with activity**: The number of wells worked on by rigs, regardless of the well operation.
3. **Rigs with activity**: The number of rigs with operations.
4. **BOP days**: The number of days during which some or all the WCE components may have been in use (or were being maintained and tested) and had any likelihood of a failure. For rigs with one BOP stack, this is equivalent to the total number of days the rig was operating, as reported in WAR data. For rigs with two BOP stacks, the number of days the rig was operating is multiplied by 1.48, based on an estimated increase in WCE components.[9] The number of **in-operation BOP days** is the subset of BOP days when the BOP system was in operation.
5. **BOP stack runs**: The number of times a subsea BOP stack was run (deployed) from the rig to the wellhead. This number also includes when the BOP stack was moved from one location to another while staying submerged (i.e., well hopping).

[8] In developing these exposure measures, WARs associated with intervention vessels were excluded.

[9] The component count of a subsea system rig with two BOP stacks divided by the component count of a subsea system rig with one BOP stack = 1.48. The details of these estimates are provided in the SafeOCS supplement, *WCE Estimated System Component Counts*, published separately.

6. **BOP stack starts**: The number of times a surface BOP stack was assembled on a surface wellhead.
7. **BOP latches and unlatches**: The number of times a subsea BOP stack was latched or unlatched from a subsea wellhead.
8. **Wells spudded**: The number of new wells started.

Analysis Information and Data Adjustments

- The terms *subsea* and *surface* reference the type of applicable BOP system, not the equipment's location (above or below the waterline); i.e., subsea exposure measures apply to rigs with subsea BOP systems, and surface exposure measures apply to rigs with surface BOP systems.
- SafeOCS may receive WCE event notifications after the publication of annual reports. If notifications are received after publication that meaningfully impact this report's results and conclusions, an addendum may be published.
- Numbers are adjusted in each annual report to reflect information provided after publication and may vary from those reported in the previous annual report. All results and references to previous data in this report represent updated numbers unless otherwise stated.
- Due to rounding, numbers in tables and figures may not add up to totals.

CHAPTER 1: NUMBERS AT A GLANCE

This report is based on data from 5,130 WCE failure events (4,754 subsea system and 376 surface system) reported to SafeOCS between 2017 and 2022 (see Table 1 and Appendix C Table 22). In 2022, the most recent year of reporting, there were 481 WCE failure events reported (438 subsea system and 43 surface system events). All reported events occurred in the Gulf of Mexico OCS, which accounts for over 99 percent of annual oil and gas production on the OCS.[10]

An average of 855 events per year were reported during the first six years of the program, from 2017 to 2022. Most of these events (741 per year on average) occurred while not in operation, i.e., during maintenance, inspection, and testing activities. Only one reported event during the six-year period, in 2017, resulted in a loss of containment of more than a barrel of wellbore fluids to the environment.

Table 1: Numbers at a Glance, 2017–2022

MEASURE	2022	2017-2022 Total	2017-2022 Average
WELLS			
Wells with Activity	273	1,618	315.2
Wells Spudded	112	822	137.0
RIGS			
Rigs with Activity	43	82	52.0
Rigs with Reported Events	31	70	35.3
OPERATORS			
Active Operators	24	39	26.5
Reporting Operators	13	25	14
BOP DAYS			
Total BOP Days	12,358	86,135	14,356
Not-in-Operation BOP Days	4,983	33,905	5,651
In-Operation BOP Days	7,375	52,230	8,705
Subsea System BOP Days	8,036	55,043	9,174
Surface System BOP Days	4,322	31,200	5,200
COMPONENT EVENTS			
Total Events Reported	481	5,130	855
Overall Event Rate	38.9	59.6	57.2
Not-in-Operation Events	396	4,446	741
In-Operation Events	85	684	114
Subsea System Events	438	4,754	792
Surface System Events	43	376	63
LOC EVENTS			
Loss of Containment Events	0	1	NA

KEY: In-operation Not-in-operation
NOTES:
- Event rate is the number of events that occurred per 1,000 BOP days.
- The 2017–22 totals for rigs, operators, and wells with activity measures represent the number of unique entities.

SOURCE: U.S. DOT, BTS, SafeOCS Program.

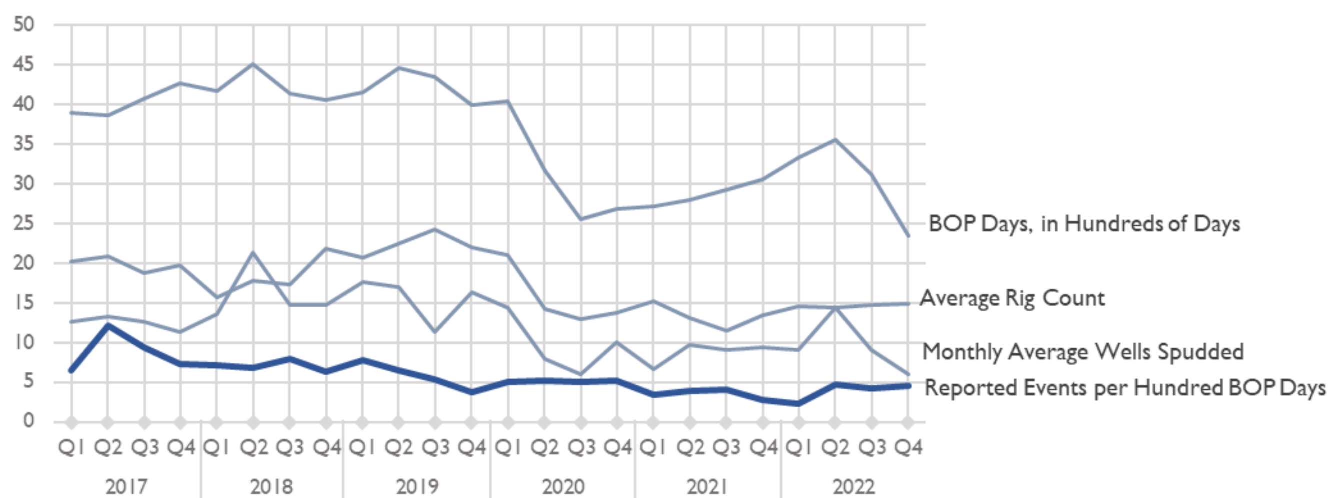
Subsea WCE system events comprised greater than 90.0 percent of failure events each year since 2017, and subsea BOP days represented 63.9 percent of BOP days overall. The difference in

[10] Outer Continental Shelf Oil and Gas Production, BSEE, https://www.data.bsee.gov/Production/OCSProduction/Default.aspx.

reported event frequency between subsea and surface systems persists after adjusting for activity levels, with 86.4 events per thousand subsea system BOP days compared to 12.1 events per thousand surface system BOP days from 2017 to 2022.

Reported events declined 70.9 percent overall from 2017 to 2021 (see Appendix C Table 22); however, the number of reported events increased in 2022 to 481, from 411 in 2021. From 2021 to 2022, when adjusted for well operations activity, measured by the number of BOP days, the rate of reported events increased 5.2 percent. Overall, events have decreased at a higher rate than activity; however, from 2021 to 2022, events increased at a higher rate than activity. Figure 1 shows levels of well activity as measured by BOP days, rig count, wells spudded, and reported events. Although the scale is different for each of these measures, they are shown together for the purpose of comparing trends. The figure shows declines in several measures of well operations activity coinciding with the onset of the COVID-19 pandemic in the second quarter of 2020. In the recovery from COVID-19, most measures of activity saw an overall increase from late 2020 into 2022. However, both BOP days and monthly average wells spudded saw a sharp dip in the second half of 2022, while the average rig count and reported events were mostly stable.

Figure 1: Levels of Well Activity in the Gulf of Mexico OCS, 2017–2022



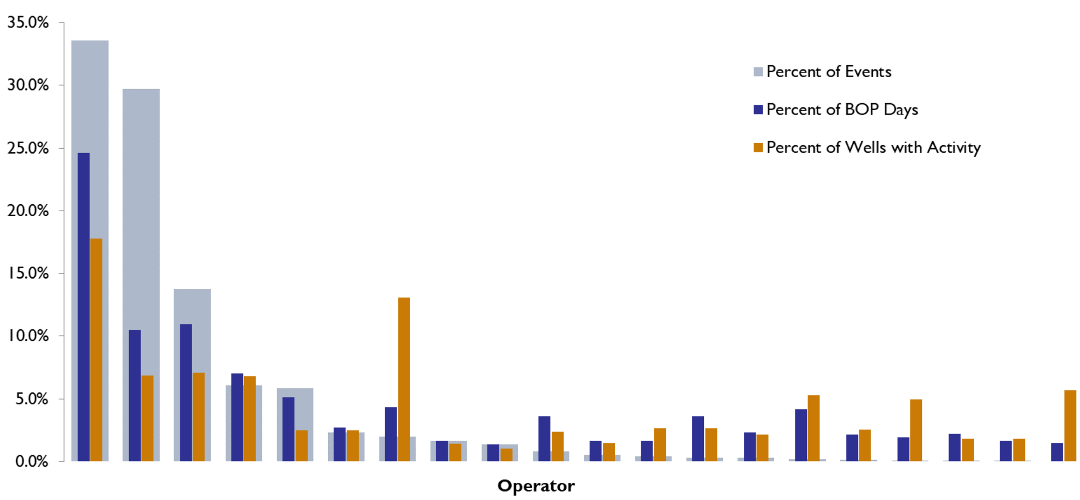
SOURCE: U.S. DOT, BTS, SafeOCS Program. Rig counts from Baker Hughes Rig Count, https://rigcount.bakerhughes.com/.

Reporting Operators

From 2017 to 2022, a total of 39 operators conducted well activities, 25 of whom have reported at least one failure event.[11] Reporting operators represent 91.8 of well activity (measured in BOP days) from 2017 to 2022.

Figure 2 shows the relative distribution of reported events, BOP days, and wells with activity among active operators over the past six years. BOP days and wells with activity are indicators of an operator's amount of well operations during the period. For most operators, the percent of BOP days and percent of wells with activity are similar. A greater percentage of wells than BOP days generally indicates the operator worked on more wells, but spent less time working on each well, compared to other operators. As shown in the figure, an operator's amount of activity is not always proportional to their reported events. For example, operators two and three had about the same levels of activity from 2017 to 2022 but show a relatively large difference in reported events. Factors that could explain this include differences in equipment, procedures, and maintenance practices between companies and potential underreporting.

Figure 2: Rig Activity and Event Reporting by Operator, 2017–2022



NOTE: Operators with less than 1.0 percent of total BOP days are not shown. These operators collectively represent 0.8 percent of reported events, 5.5 percent of BOP days, and 7.8 percent of wells with activity.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

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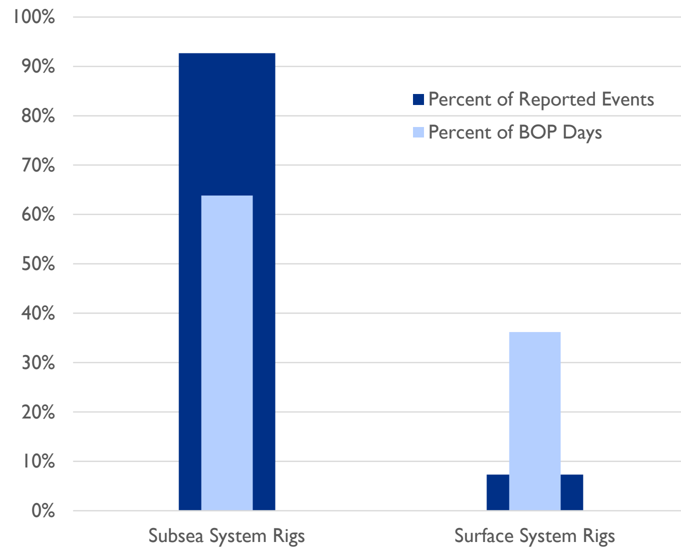
[11] The 39 operators had at least one BOP day reported in well activity report data. An additional three operators had at least one WCE event reported to SafeOCS, but no reported BOP days in well activity report data.

Rigs with Events

Rigs are the facilities on which well control equipment is operated. Examining the distribution of reported events among rigs can provide insights regarding failures and reporting trends. Between 2017 and 2022, 82 rigs (41 rigs with subsea BOP stacks and 41 rigs with surface BOP stacks) had some level of well activity. Although the quantity of rigs is evenly split, Figure 3 shows that most well activity (63.8 percent) was conducted by subsea system rigs, which contributed 92.7 percent of reported events over the six-year period.

Figure 3: WCE Reporting by WCE System Type, 2017–2022



NOTE: Subsea system rigs represented include drillships, semisubmersibles, and dynamically positioned (DP) semisubmersibles. Surface system rigs represented primarily include platform rigs and jackups.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Of the 82 rigs with well activity from 2017 to 2022, 70 were associated with at least one failure event. Subsea system rigs experienced an average of 115.9 events total (standard deviation (SD) 141.8), and 86.4 events per thousand BOP days over the six-year period. Surface system rigs experienced an average of 9.2 events total (SD 11.1) and 12.1 events per thousand BOP days. Complexity and component population may partially explain the difference in number events experienced by subsea systems as compared to surface systems.

Timeliness of Event Reporting

Throughout the reporting period (2017-2022), 39.8 percent of reported events were submitted within 30 days of the event date. For 2022, the percent (38.0 percent) remained on par with the average. Similarly, events in 2022 requiring further investigation took longer to be submitted than those where the cause was immediately known, 19.3 percent and 80.7 percent, respectively. Over the six-year period, 30.5 percent of events with further investigation were submitted within 30 days, compared to 44.7 percent of events where the cause was immediately known.

WCE Events Identified in WAR Data

BTS uses BSEE well activity report data not only to estimate activity levels (i.e., BOP days), but also to cross-reference the timing and occurrence of failures and identify those that may not have been reported to SafeOCS, resulting in a better approximation of the complete set of failure events. Since 2019, SafeOCS has identified failure events including BOP stack pulls through a review of WAR data. From 2019 to 2022, 41 BOP stack pull events not reported to SafeOCS were identified from WAR data and included in aggregated analyses presented in this report. Most of these were for surface WCE systems (see Table 2). Events other than BOP stack pulls are also identified in WAR data, however they are excluded from the aggregated statistics presented in this report due to limited available event information.

Table 2: Unreported BOP Stack Pull Events Identified in WAR Data, 2019–2022

	2019	2020	2021	2022	Total
Subsea WCE Systems	0 (0.0%)	3 (37.5%)	1 (33.3%)	1 (20.0%)	5 (20.8%)
Surface WCE Systems	16 (44.4%)	6 (66.7%)	6 (37.5%)	8 (57.1%)	36 (48.0%)

SOURCE: U.S. DOT, BTS, SafeOCS Program.

CHAPTER 2: SUBSEA WCE SYSTEM EVENTS

Reported subsea WCE system events declined each year from 2017 to 2021, but increased in 2022, as shown in Table 3 and Appendix C Table 23. However, activity levels (wells and BOP days) remained at nearly the same level in 2022 as in 2021. There were slightly more active operators (one more) and more rigs with activity (three more) in 2022 than in 2021.

As in previous years, most subsea system events in 2022 (89.7 percent) were found while not in operation, i.e., during maintenance, inspection, and testing. Subsea stack pulls increased from three in 2021 to five in 2022. About 4.4 percent of successful subsea BOP stack runs—meaning the BOP stack was deployed to the wellhead on the seafloor, assembled on the wellhead, and went into operation—eventually had an unplanned BOP stack pull during the six-year period.

Table 3: Subsea System Numbers at a Glance, 2017–2022

MEASURE	2022	2017-2022 Total	2017-2022 Average
WELLS			
Wells with Activity	134	650	157.0
Wells Spudded	50	435	72.5
RIGS			
Total Rigs with Activity	24	41	27.2
With One Subsea Stack	5	13	7.2
With Two Subsea Stacks	19	28	20.0
Rigs with Reported Events	20	38	22.0
OPERATORS			
Active Operators	15	23	16.8
Reporting Operators	11	20	10.5
BOP DAYS			
Total BOP Days	8,036	55,043	9,174
Not-in-Operation BOP Days	3,724	25,064	4,177
In-Operation BOP Days	4,311	29,979	4,997
COMPONENT EVENTS			
Total Events Reported	438	4,754	792
Overall Event Rate	54.5	86.4	83.0
Not-in-Operation Events	381	4,265	710.8
Not-in-Operation Event Rate	102.3	170.2	165.7
Not-in-Operation Events per Well	2.8	6.6	4.4
In-Operation Events	57	489	81.5
In-Operation Event Rate	13.2	16.3	15.6
In-Operation Events per Well	0.4	0.8	0.5
BOP STACK MOVEMENTS			
Total Stack Runs	136	1,056	176.0
Successful Runs	126	911	151.8
Stack Pulls	5*	40	6.7
LOC EVENTS			
Loss of Containment Events	0	1	NA

KEY: In-operation Not-in-operation

NOTES:
- Event rate is the number of events that occurred per 1,000 BOP days.
- The 2017–22 totals for rigs, operators, and wells with activity measures represent the number of unique entities.

* Includes some BOP stack pulls identified in WAR. Table 2 provides counts. These are not included in *Total Events Reported*.

SOURCE: U.S. DOT, BTS, SafeOCS Program.

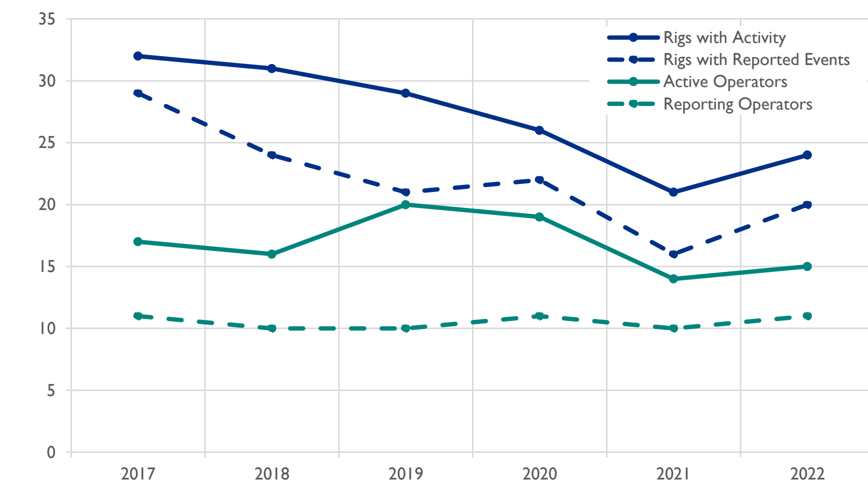
Event Reporting Levels

As shown in Figure 4, changes in the number of active operators for subsea WCE systems were greater from year to year than changes in reporting operators, which remained relatively stable at 10 or 11 operators each year. In contrast, changes in the number of rigs with reported events tend to follow changes in the number of rigs with activity more closely, with only one year having differing directions of change (2019 to 2020). This may suggest that other factors in addition to activity levels may contribute to changes in reporting. From 2021 to 2022, both rig activity and associated reports as well as operator activity and reports increased at the same rates, respectively.

Frequently Reported Components

From 2017 to 2022, 124 different components were reported as having failed on subsea WCE systems. As in previous years, the most frequently reported components in 2022 were control valves (SPM valves and shear seal valves), shuttle valves, pressure gauges, and ram block seals (see Appendix D). Figure 5 illustrates each reported component's percentage of events over the six-year period compared to that component's percentage of the typical component population on a rig with two subsea BOP stacks. The orange (not in operation) and blue (in operation) stacked bars together show the component's percentage of total subsea events and the wider light blue bars show each component's percentage of the typical component population.

Figure 4: Reporting and Activity Levels for Subsea Systems, 2017–2022



SOURCE: U.S. DOT, BTS, SafeOCS Program.

All else being equal, one could expect a component's percentage of events to be consistent with its percentage of the population;[12] however, as shown on the figure, that is not the case for most components. A ratio less than 1.0 indicates that this component experienced a lower percentage of failures compared to its percentage of the population. This could be influenced by a long service life expectancy. Shuttle valves, pressure gauges, pod packers and gate valve hardware are examples of components with failure ratios less than one.

A failure ratio greater than 1.0 indicates that other factors are influencing the number of failures (e.g., frequency of use, circuit complexity, operating environment, and installation and maintenance practices). Control valves and ram block seals each had a failure ratio[13] greater than 1.0, meaning they had a disproportionately high number of reports as compared to their population, relative to other components. Regulators and choke and kill valves are also two components with high failure ratios. Both had less than 1.0 percent of the population but 11.5 percent and 4.4 percent of the failures, respectively.

As shown on the chart, most component failures are detected while not-in-operation due to the extensive scheduled maintenance, inspection, and testing (MIT) to which they are frequently subjected; however, certain components do not have specified replacement schedules or maintenance routines that might detect degradation. Many of these components are in use during the entire time that the BOP stack is in operation, and over the six-year period the number of BOP days in-operation comprised more than half (54.4 percent) of total BOP days.[14] Some components might also be considered consumable,[15] comparatively low cost, or have no suitable early detection tests; and are therefore may be "run to failure" in certain cases. The data suggests that these components fail in operation at a frequency more consistent with the amount of time that they are in operation, as compared to other components which are subject

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[12] Component estimates are provided in the SafeOCS supplement, *WCE Estimated System Component Counts*, published separately.

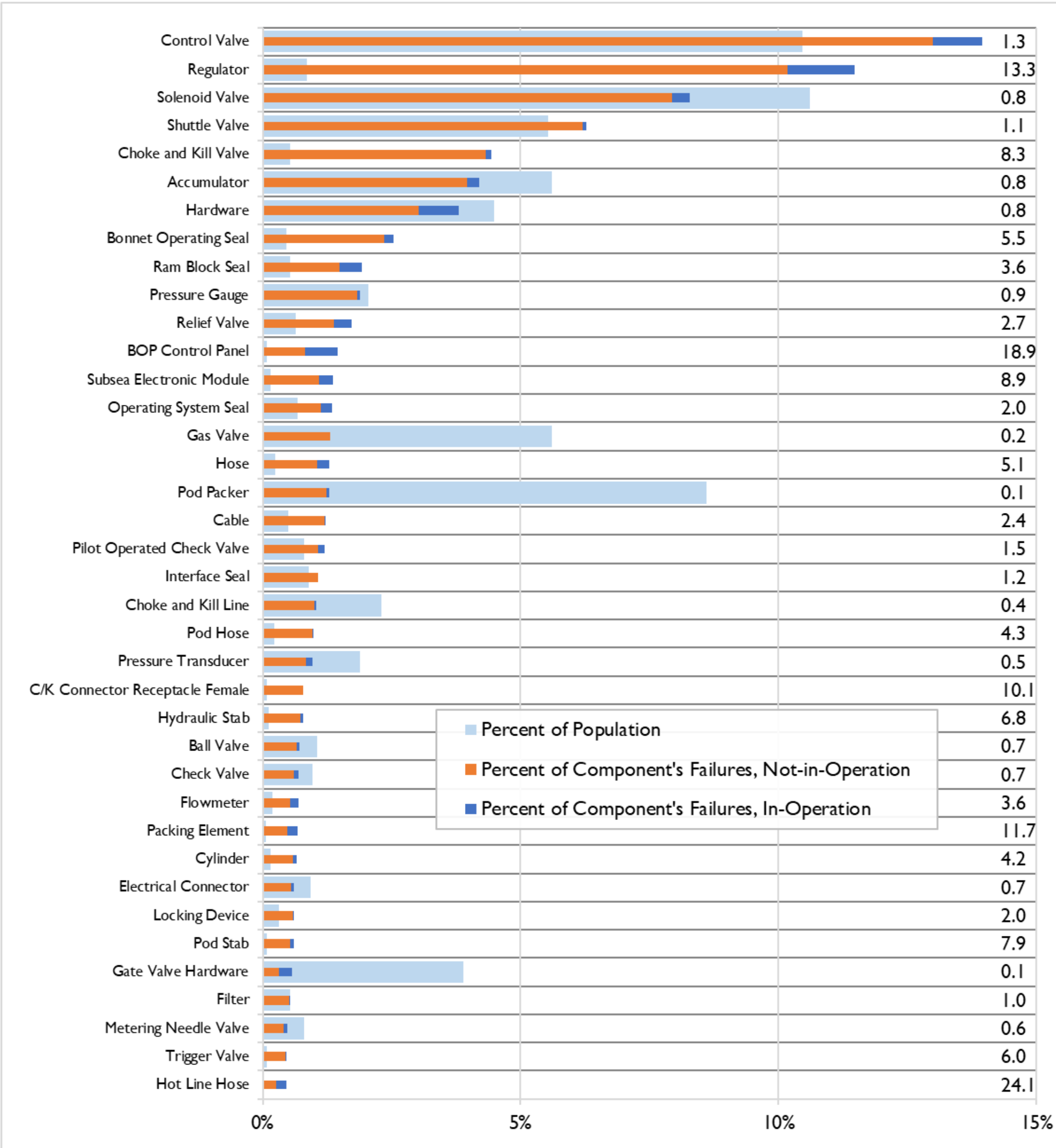
[13] Ratio = a component's percent of failures divided by that component's percent of the population.

[14] BOP days in operation/Total BOP days.

[15] Consumables, in this context, are seals that have an indeterminable expected life because of variables in the operating conditions, and therefore do not have a replacement cycle.

to more extensive on-deck MIT. Some examples of the former case include BOP control panels and pressure temperature sensors.

Figure 5: Subsea System Component Failures Relative to Component Population, 2017-22



NOTE: Components with 0.5 percent or less of failures are excluded and total 10.4 percent of all subsea system failures. Piping/Tubing (5.1 percent of failures) and Studs and Nuts (0.1 percent of failures) are not represented in the table as they do not have an estimated population average. Failure ratio, shown in righthand column, represents the component's percent of failures divided by that component's percent of the population.

SOURCE: U.S. DOT, BTS, SafeOCS Program.

For 2022, four components were identified as having both a failure ratio greater than 1.0 and four or more in-operation events in 2022; the following provides further discussion of these components:

Control Valves: These include both sub-plate mounted (SPM) cartridge valves and shear-seal valves, and amount to 14.5 percent of all reported subsea system failures from 2017 to 2022, and 14.3 percent in 2022 alone. Both styles are hydraulically piloted and perform similar functions, directing power fluid to operate a function such as closing a ram or annular preventer. SPM valves use elastomeric seals, while shear-seal valves use metal-to-metal sealing technologies. SPM valves tend to fail due to damaged o-rings. The shear-seal valves have a metal seal ring that seals on a metal seal plate, and these typically fail when the quality of the highly polished surface finish between these parts is degraded or otherwise compromised. In 2022 there were 18 different SPM valve types (i.e., part numbers) and six different shear-seal valve types reported for 39 failures.

Regulators: There were 546 reported events involving regulators from 2017 to 2022, with 42 occurring in 2022. Regulators can vary widely, and 69 different part numbers were reported during the six-year period.[16] Four regulators failed in operation in 2022, and they were all associated with diverter systems. Regulators are among the hardest worked hydraulic components in the system, because even when everything else is on standby, they are constantly making minute adjustments because of movement or temperature fluctuations. Additionally, regulators that are in the pod(s) each supply a different circuit of various numbers of control valves, and over time, the regulator passes much more flow than any control valve and therefore has an increased risk of compromising the polished seal surfaces similar to the those in the shear-seal valves.

Ram Block Seals: Since 2017, there have been a total of 91 reported ram block seal failures. Five of 17 failures in 2022 occurred while the BOP was in operation. Ram block seals are consumable elastomeric seals that seal around the pipe in the case of pipe ram seals, or seal between the opposing ram blocks in the case of shear rams. They are considered having failed when they stop holding pressure. If, as in the case of pipe rams, they are closed on moving pipe,

[16] Part numbers are unknown on four of the events.

then the elastomer will wear more quickly. The rate of wear may be affected by not only such movement, but also the chemical, solids content, or temperature of the wellbore fluids. While it is normal for the operator to have the elastomer checked against the fluids that are planned to be used, there is no standard test against all wellbore fluid variables.

BOP Control Panels: From 2017 to 2022, there have been 57 reported BOP control panel failures. In 2022, 10 power or communication issues were reported; seven in operation and three not in operation. Due to redundancy, none of these events disrupted operations and control was not compromised. There is no typical replacement schedule as the parts are generally run to failure.

Failure Types

As in previous years, most events in 2022 were a type of leak, comprising 73.6 percent of subsea system events overall. As shown in Table 4, external leaks were the most frequently observed failure, which is not unexpected as most components are used to control and contain fluids present during operations. Communication/signal issues were up slightly in 2022 compared to the previous 5 years, at 6.2 percent.

Table 4: Failure Types of Subsea System Events, 2017–2022

FAILURE TYPE	2017 (n=1,300)	2018 (n=1,128)	2019 (n=908)	2020 (n=614)	2021 (n=365)	2022 (n=439)	Total (n=4,754)
LEAKS							
External Leak	49.8%	46.6%	60.1%	54.1%	50.7%	44.1%	51.1%
Internal Leak	28.1%	24.3%	20.6%	27.7%	21.9%	29.5%	25.4%
Undetermined Leak	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.1%
OTHER							
Communication / Signal Issue	4.2%	2.8%	3.3%	3.1%	2.5%	6.2%	3.6%
Electrical Issue	1.6%	1.8%	3.0%	1.8%	1.9%	1.1%	1.9%
Fail to Function on Command	2.6%	2.7%	2.4%	3.4%	9.0%	4.1%	3.3%
Inaccurate Indication	2.2%	3.0%	2.5%	2.0%	3.0%	5.3%	2.8%
Mechanical Issue	9.7%	16.7%	6.3%	5.0%	6.8%	5.9%	9.5%
Process Issue	1.1%	1.5%	1.1%	1.8%	1.4%	0.7%	1.3%
Unintended Operation	0.2%	0.2%	0.1%	0.0%	0.3%	0.0%	0.1%
Other	0.5%	0.1%	0.6%	1.1%	2.5%	3.2%	0.9%
TOTALS	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

SOURCE: U.S. DOT, BTS, SafeOCS Program.

Although there is not a specific field on the data collection form to capture leak volume or rate (and leaks are rarely collected and measured), event narratives indicate that nearly all of the leaks reported to SafeOCS between 2017 and 2022 comprise small volume control fluid leaks. Such leaks can be categorized as (a) those that are too small in volume to register on instruments during in-operation activities but can sometimes be seen by the crew when the BOP stack is on deck during maintenance, inspection, and testing, or (b) leaks at a rate that might be considered allowable by the OEM but not necessarily by the rig owner procedures. Both types of leaks have very small volumes (measured in drops per minute), and therefore do not typically affect on-going operations.

Though leaks can affect all hydraulic components, those most subject to external leaks include several of the most frequently reported: regulators, solenoid valves (hydraulic), SPM valves, slide (shear-seal) valves, piping/tubing, and accumulators. This is partially explained by the nature of the component, as when most of these components leak, it is almost always externally visible. For shuttle valves, the most frequent failure type is internal leak. Together, reported external leaks of these seven types of components total 63.9 percent of their total failure events, 60.7 percent of all control fluid external leaks, and 31.1 percent of all events since 2017. Sometimes, an internal leak is detected by visual observation (e.g., from a vent port), which could lead to some level of inconsistency in reporting of control fluid leaks as internal versus external.

Except for one event involving ram door seals that caused a loss of containment in 2017, there have not been any reported events involving a loss of containment of more than a barrel of wellbore fluid. In 2022, a review of reported events was conducted to identify events that could have resulted in a loss of containment of more than a barrel of wellbore fluid. Four events were identified and summarized below, three of which occurred in 2019 and one in 2022. The specific volumes released were not provided in the reports; however, based on review of the reported circumstances it is unlikely any events resulted in a loss greater than one barrel. Similar to control fluid leak volumes, there is not a specific field on the data collection form to capture the leak volume or rate for wellbore fluid leaks. Further, it is difficult to measure small leaks of wellbore fluids during operations.

- Two of the events were reported on the same rig on the same day when both the choke and the kill flex hoses were found leaking externally during a pressure test. The BOP stack was pulled to replace them.
- A third event was described as a grease fitting on a kill valve allowing sea water ingress during a negative pressure test. The BOP stack was pulled, and the kill valve was repaired.
- In the fourth event, a ring gasket on the riser connector between the BOP and LMRP was found to be leaking after the BOP had been in use for several weeks (note that routine testing continued during the period of time the BOP was in use prior to detection of the leak). Inspection revealed a paint chip between the gasket and the gasket sealing area.
- All other reported external leaks have involved water-based control fluid, which is vented into the ocean as part of the system design.

Detection Methods

Most subsea system events from 2017 to 2022 (89.7 percent) were detected while not in operation, i.e., during maintenance, inspection, and testing. As shown in Table 5, 2022 was the first year that a higher percentage of not-in-operation events were detected via casual observation (33.3 percent) than during function testing (20.7 percent). This is an area for further study.

Table 5: Detection Methods for Not-in-Operation Subsea System Events, 2017–2022

	DETECTION METHOD	2017 (n=1,152)	2018 (n=1,022)	2019 (n=826)	2020 (n=561)	2021 (n=323)	2022 (n=381)	Total (n=4,265)
	Casual Observation	10.0%	9.0%	11.4%	13.0%	13.9%	33.3%	12.8%
	Continuous Condition Monitoring	6.0%	3.6%	8.2%	5.7%	10.2%	0.5%	5.7%
	On Demand	0.6%	0.6%	0.8%	1.1%	1.5%	1.3%	0.8%
	Periodic Condition Monitoring	1.0%	1.6%	2.3%	3.9%	4.6%	8.4%	2.7%
	Corrective Maintenance	1.2%	0.5%	0.2%	0.4%	0.9%	0.3%	0.6%
	Periodic Maintenance	3.5%	7.0%	6.9%	4.5%	5.3%	10.8%	5.9%
MIT	Inspection	16.9%	22.9%	18.6%	13.7%	22.6%	10.2%	18.1%
	Function Testing	44.1%	39.2%	35.0%	39.8%	24.5%	20.7%	37.0%
	Pressure Testing	16.7%	15.6%	16.5%	18.0%	16.4%	14.4%	16.3%

KEY: Not-in-operation MIT: maintenance, inspection, testing
SOURCE: U.S. DOT, BTS, SafeOCS Program.

As seen in Table 6, most in-operation events from 2017 to 2022 were detected via continuous condition monitoring (20.7 percent), followed by pressure testing (17.8 percent) and casual observation (17.4 percent). In 2022, fewer in-operation events were detected through continuous condition monitoring compared to the six-year average, while both 2021 and 2022 saw more events detected via periodic condition monitoring than the previous four years.

Table 6: Detection Methods for In-Operation Subsea System Events, 2017–2022

	DETECTION METHOD	2017 (n=149)	2018 (n=106)	2019 (n=82)	2020 (n=53)	2021 (n=42)	2022 (n=57)	Total (n=489)
	Casual Observation	16.8%	16.0%	17.1%	17.0%	16.7%	22.8%	17.4%
	Continuous Condition Monitoring	18.8%	20.8%	29.3%	30.2%	21.4%	3.5%	20.7%
	On Demand	1.3%	0.9%	1.2%	7.5%	4.8%	5.3%	2.7%
	Periodic Condition Monitoring	9.4%	8.5%	7.3%	7.5%	21.4%	24.6%	11.5%
MIT	Periodic Maintenance	0.0%	1.9%	0.0%	7.5%	0.0%	0.0%	1.2%
MIT	Inspection	16.1%	19.8%	13.4%	7.5%	7.1%	8.8%	13.9%
MIT	Function Testing	16.1%	11.3%	12.2%	11.3%	23.8%	19.3%	14.9%
MIT	Pressure Testing	21.5%	20.8%	19.5%	11.3%	4.8%	15.8%	17.8%

KEY: In-operation MIT: maintenance, inspection, testing
SOURCE: U.S. DOT, BTS, SafeOCS Program.

For the most frequently reported components (see Appendix D), the majority of events were found via function testing, except for accumulators and piping/tubing. Accumulator events had the same number of events found via inspection, function testing, and periodic maintenance from 2017 to 2022. Piping/tubing events were found mostly via inspection. Apart from accumulators, external leaks of these components were found most often during not-in-operation function testing (44.3 percent from 2017 to 2022), pressure testing, inspection, and casual observation. External leaks on accumulators were found most frequently during inspection.

Root Causes of Events

While most events from 2017 to 2022 (46.6 percent) were attributed to wear and tear, the percentage citing wear and tear decreased each year, reaching a low of 29.3 percent in 2021 (see Table 7). However, in 2022, the percentage increased slightly to 32.6 percent. After wear and tear, the most common root causes over the six-year period have been design issue and maintenance error. From 2021 to 2022, procedural error increased from 16.7 to 25.6 percent, and reports without a root cause listed increased for the first time, from 0.3 percent in 2021 to 4.3 percent in 2022. Most of the reports without a root cause were from newer participants, suggesting that additional training on reporting may be needed.

Table 7: Root Causes of Subsea System Events, 2017–2022

REPORTED ROOT CAUSE	2017 (n=1,301)	2018 (n=1,128)	2019 (n=908)	2020 (n=614)	2021 (n=365)	2022 (n=438)	Total (n=4,754)
Design Issue	11.0%	17.6%	19.7%	19.9%	12.6%	7.3%	15.2%
QA/QC Manufacturing	5.9%	12.2%	6.3%	5.7%	6.6%	5.5%	7.5%
Maintenance Error	11.8%	9.3%	12.2%	13.0%	20.3%	13.9%	12.3%
Procedural Error	2.2%	3.8%	13.2%	13.4%	16.7%	25.6%	9.4%
Documentation Error	0.4%	0.7%	0.1%	11.6%	5.2%	0.7%	2.3%
Wear and Tear	57.6%	52.9%	45.0%	33.7%	29.3%	32.6%	46.6%
Other	0.5%	0.4%	0.1%	0.3%	0.3%	0.0%	0.3%
NOT DETERMINED							
Inconclusive	0.2%	0.0%	0.3%	0.0%	0.3%	0.2%	0.1%
Assessment Pending	7.2%	2.7%	2.8%	2.3%	8.5%	9.8%	5.0%
Not Reported	3.2%	0.3%	0.2%	0.2%	0.3%	4.3%	1.4%
TOTALS	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

SOURCE: U.S. DOT, BTS, SafeOCS Program.

Regarding the high proportion of wear and tear relative to other root causes, detailed review of notifications indicates that the submitted information does not always provide adequate or meaningful support for the reported root cause. Additionally, depending on the OEM-designated design life of a component, wear and tear may be more acceptable for certain events than others. This is an area for further evaluation.

Wear and tear was also the top root cause for failures of frequently reported components from 2017 to 2022, listed in Table 8. In addition to wear and tear, commonly reported root causes for each component included design issue for regulators, slide (shear-seal) valves, and accumulators, and maintenance error and QA/QC manufacturing for piping/tubing. Supporting information for failures attributed to design issue has been infrequent.

Table 8: Root Causes of Frequently Reported Components for Subsea Systems, 2017–2022

REPORTED ROOT CAUSE	Regulator	Solenoid Valve Hydraulic	SPM Valve	Slide (Shear-Seal) Valve	Shuttle Valve	Piping/Tubing	Accumulator
Design Issue	22.3%	1.6%	6.4%	16.9%	4.7%	6.6%	19.0%
QA/QC Manufacturing	3.8%	2.7%	3.6%	4.3%	2.0%	19.3%	3.4%
Maintenance Error	9.9%	15.4%	17.7%	8.0%	18.8%	20.2%	6.1%
Procedural Error	16.7%	13.6%	2.5%	13.0%	18.8%	2.9%	11.2%
Documentation Error	9.9%	6.6%	1.1%	4.7%	0.0%	0.0%	0.0%
Wear and Tear	33.2%	58.2%	61.6%	50.5%	54.0%	48.1%	57.0%
Other	0.4%	0.3%	1.1%	0.0%	0.3%	0.8%	0.6%
NOT DETERMINED							
Inconclusive	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Assessment Pending	2.7%	0.8%	3.6%	2.7%	0.3%	1.2%	2.8%
Not Reported	1.1%	0.8%	2.5%	0.0%	1.0%	0.4%	0.0%

SOURCE: U.S. DOT, BTS, SafeOCS Program.

Wear and tear continues to be the predominantly reported root cause for 2022 events, partially due to the difficulty of the varying environments under which components are subject as compared to manufacturer's controlled tests. Equipment owners may customize their maintenance plans for a component based on their field experience with that component or in accordance with API S53 7.6.9.4, which states: "Rig-specific procedures shall be developed for the installation, operation, and maintenance of BOPs for the specific well and environmental conditions."

Consequential Components

In addition to examining frequently reported component events, it is also useful to examine infrequent component events that may have higher potential consequence, such as failures of the wellhead connector or LMRP connector (sometimes referred to as a riser connector), which connect and seal the BOP stack to the wellhead, and the LMRP to the lower stack, respectively.

Since 2017, there have been 24 events associated with the wellhead connector. Twelve of these events were a failure of the operating system seals (three in 2022), nine were related to accessories such as indicator rods, nudge pins and gasket retainers. All of these events were detected not-in-operation and none compromised wellbore integrity.

From 2017 to 2022, there have been 16 events associated with the LMRP connector; eight of these events involved an operating system seal (four in 2022), and six events were related to accessories. Fifteen of these events were detected not in operation. The one event which occurred in operation was a leak observed by the ROV from the LMRP connector to riser mandrel interface, resulting in an unplanned stack pull. Investigation found a flake of paint trapped on the ring gasket between the LMRP and the lower BOP stack, which had caused the leak.

Not-in-Operation Events

Events occurring while not in operation, when the equipment is being maintained, inspected, or tested (MIT) before or after operations, have lower safety and environmental risk than in-operation events. However, events occurring not-in operation are important to consider, as they may provide insight on the prevention of the same or similar events occurring in-operation. From 2017 to 2022, 89.7 percent of subsea system events were detected while not in operation. As discussed in more detail in Appendix B, the phases of not-in-operation MIT include between wells maintenance, pre-deployment testing, deployment testing, and initial subsea testing (sometimes referred to as initial latch-up testing). Most not-in-operation failures are found during the first two phases, while the BOP stack is on deck. The following discussion focuses on the latter two phases, after the BOP stack has begun deployment:

- *Deployment Testing:* This phase is after pre-deployment testing while the BOP is being deployed to the wellhead. System monitoring and testing are conducted throughout this process.
- *Initial Subsea Testing:* This is the final phase of not-in-operation MIT and is similar to pre-deployment testing, but with the added element of hydrostatic pressure due to operational depth, the effects of which cannot be checked or verified until the BOP stack is at operating depth. This testing confirms wellbore integrity. The BOP stack must pass all initial latch-up testing before going into operation.

These final testing periods are the first opportunity for testing the assembled system and finding failures after general MIT has been completed, but before the BOP stack is in operation. The BOP and BOP control systems are considered properly tested only when they are fully assembled in the configuration that will be used while constructing the well. This means that until the initial subsea testing is complete, then MIT is not finished. If a failure is found during deployment or initial subsea testing, the operator may be able to make repairs (using an ROV, or if the component is accessible on deck), or continue operations without repair while still ensuring safe operations. Without repair, redundancy, or a management of change (MOC) waiver, the BOP stack must be retrieved to repair the component. Retrievals are not considered BOP stack pulls, since the BOP stack has not yet gone into operation, the well is not open, and therefore does not need to be made safe before retrieving the BOP stack. If a component failure is not identified during the last two phases of testing, it could result in a BOP stack pull instead of a retrieval.

Of 1,056 BOP stack runs between 2017 and 2022, 911 were successful, meaning the BOP stack passed initial subsea testing and went into operation. Of the 145 BOP stack runs that were unsuccessful, meaning that the BOP stack needed to be retrieved and go through testing again before operations could commence, 97 retrievals were the result of a reported subsea system component failure. (Other circumstances, such as weather events, may also lead to BOP stack retrievals.) As shown in Table 9, from 2017 to 2022, 260 events were identified during the last two phases of testing, 123 of which resulted in a retrieval (in some cases, multiple failures were associated with a single retrieval). In the remaining cases, repair was accomplished without a BOP stack retrieval or operations continued without repair (under redundancy or an MOC waiver, for example).

Table 9: Retrievals and Events During the Last Two Phases of Testing, 2017–2022

Measure	Events during Deployment Testing	Events during Initial Subsea Testing	Total
Stack Retrievals	37	60	97
Total Events	113	147	260
Operations Continued without Repair	16	19	35
Component Repaired (in situ)	46	56	102
Events Contributing to Stack Retrieval	51	72	123

SOURCE: U.S. DOT, BTS, SafeOCS Program.

Table 10 lists the WCE system subunits involved in failure events that occurred during deployment or initial subsea testing. Most occurred on the BOP controls and BOP stack, and a stack retrieval was required for just under half of the events involving these subunits. Of note, the choke manifold and diverter systems are accessible on deck, and therefore failures associated with these subunits generally would not require retrieval of the BOP stack to address (with limited exceptions).

Table 10: Events During the Last Two Phases of Testing (by Subunit) 2017–2022

Subunit	Events during Deployment Testing			Events during Initial Subsea Testing			Total
	Operations Continued without Repair	Component Repaired (in situ)	Events Contributing to Stack Retrieval	Operations Continued without Repair	Component Repaired (in situ)	Events Contributing to Stack Retrieval	
Auxiliary Equipment					2		2
BOP Controls	14	25	31	8	9	33	120
BOP Controls Emergency Automated Functions		1	7		3	9	20
BOP Controls Secondary ROV Acoustic					4	8	12
BOP Stack		4	12		4	22	42
Choke Manifold System		3			21		24
Diverter System		10			13		23
Riser System		3	1				4

SOURCE: U.S. DOT, BTS, SafeOCS Program.

From 2017 to 2022, 69 different types of components failed during deployment or initial subsea testing. Table 11 lists the subset of component types that experienced at least five failures during these phases. For most of these components, redundancy can allow operations to continue without repair or the component can be repaired without retrieval. For some component types, such as choke and kill operator hardware, all events during these phases resulted in a BOP stack retrieval.

Though most systems and components can be thoroughly tested prior to the last two testing phases, some systems and components can be only partially tested, as they are not physically connected to the system or exposed to the full effects of hydrostatic pressure until the BOP stack is latched to the wellhead. These include the riser system, telescopic joint, stack mounted electrical equipment, and the wellhead-connector.[17] Thirty-seven of the 260 total events (14.2 percent) found during the last two phases of testing involved these systems: 23 failures on the BOP control pod, 10 failures of the stack mounted electrical equipment, one on the telescopic joint, one on the wellhead connector, and one failure on the riser system. The remaining 223

[17] Stack mounted electrical equipment components include PBOF cables, pressure temperature sensors, electrical connectors, inclinometers, riser control boxes, cables, and pressure transducers.

events found during deployment and initial subsea testing involved components subject to thorough testing on deck before BOP stack deployment.

Table 11: Events During the Last Two Phases of Testing (by Component) 2017–2022

Component	Events during Deployment Testing			Events during Initial Subsea Testing			Total
	Operations Continued without Repair	Component Repaired (in situ)	Events Contributing to Stack Retrieval	Operations Continued without Repair	Component Repaired (in situ)	Events Contributing to Stack Retrieval	
Hardware		1			19		20
SPM Valve	4	3	3		2	7	19
Regulator		5	2	5		6	18
Ram Block Seal				2		8	10
Slide Shear Seal Valve		1	3	2	2	2	10
Electrical Connector	2	1	5			1	9
Pressure Transducer	2		4	2			8
Pressure Gauge					1	6	7
Choke and Kill Valve			2	2	1	2	7
Piping Tubing				1	2	3	6
Choke and Kill Operator Hardware			6				6
Subsea Electronic Assembly (SEA)	4	1				1	6
Flowline Seal		2			3		5
Ball Valve		1			4		5
Pilot Operated Check Valve		1				4	5
Locking Device				1	1	3	5
Metering Needle Valve		1			2	2	5
Other components	4	29	26	4	19	27	109

NOTE: Components with fewer than five failures excluded.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

In-Operation Events Including BOP Stack Pulls

From 2017 to 2022, a total of 489 in-operation events were reported for subsea WCE systems, including 35 subsea BOP stack pulls. An additional five subsea BOP stack pulls were identified in WAR data. When adjusted for the level of activity, an average of 15.6 events occurred per thousand in-operation BOP days over the six-year period, reaching a low of 10.8 events per thousand in-operation BOP days in 2021. Both the in-operation activity level and number of in-operation events increased in 2022 to just under the 2020 level.

Table 12 shows the equipment involved in events leading to subsea BOP stack pulls from 2017 to 2022, as well as the total number of in-operation events for those component combinations.

Of the 22 different component types associated with subsea BOP stack pulls (one component type is unknown from a stack pull identified in WAR data), piping/tubing has been associated with the most stack pull events (seven). SPM valves, annular packing elements, ram block seals, operating system seals, and flex loop/hose have been associated with at least two BOP stack pulls each since 2017 (a total of 16, as shown in Table 12). The remaining component types have been associated with one BOP stack pull each since 2017.

A component's location and function within the BOP system may influence the likelihood that an in-operation event results in a BOP stack pull. For example, of 19 in-operation ram block seal failures on the pipe ram preventer, which must be tested every seven days, three led to a BOP stack pull (15.8 percent), compared to the sole in-operation event resulting in a BOP stack pull for the ram block seal on the shear ram preventer, which is only required to be functioned every 21 days. Less use can equate to longer life, subject to other variables. In another example, each of the reported in-operation piping/tubing failures on the emergency automated systems led to stack pulls, while less than half of those on other systems led to stack pulls.

External leaks were the most frequent failure type among BOP stack pull events, attributed to 60.0 percent from 2017 to 2022. Design issue was the most frequently reported root cause, cited for eight events. For eleven events, no definitive root cause was listed. The five subsea stack pulls that occurred in 2022 are discussed further below:

- A pod receptacle experienced an adjustment issue that caused five pod packers to leak.
- A ram block seal on the lower pipe ram preventer failed to hold pressure.
- A ring gasket on the riser connector between the BOP and LMRP was found to have leaked. Inspection revealed a paint chip between the gasket and the gasket sealing area.
- Increased pump cycle time troubleshooting revealed a code-62 flange leaking on the piping/tubing on the shear accumulator circuit. During inspection an o-ring was found damaged.
- An additional stack pull, identified in WAR data, was due to leak on the autoshear/deadman circuit. No further details were available.

Table 12: Component Combinations of Subsea BOP Stack Pulls, 2017–2022

Subunit	Item	Component	2017-2022 In-Operation Events	2017-2022 Stack Pulls
BOP Controls	BOP Control Pod	SPM Valve	19	2
		Piping/Tubing	6	2
		Interconnect Cable	1	1
		Cylinder	3	1
		Check Valve	2	1
		Pod Receptacle	5	1
	BOP Controls Stack Mounted	Piping/Tubing	5	2
		Shuttle Valve	2	1
		Electrical Connector	1	1
		Hose	11	1
	Reels Hoses Cables	MUX Cable	2	1
BOP Controls Emergency Automated Functions	Autoshear Deadman EHBS	Piping/Tubing	3	3
		SPM Valve	3	1
		Timing Circuit	1	1
BOP Stack	Annular Preventer	Packing Element	10	4
		Operating System	6	2
	Pipe Ram Preventer	Ram Block Seal	19	3
		Bonnet Face Seal	1	1
	Riser Connector	Ring Gasket	1	1
	Shear Ram Preventer	Ram Block Seal	1	1
		Ram Block Hardware	1	1
		Bonnet Operating	6	2
	Stack Choke and Kill System	Flex Loop/Hose	3	2
		Choke and Kill Valve	4	1
Riser System	Riser	Choke and Kill Line	1	1
	Integrated Riser Joint	Unknown	1	1
	Telescopic Joint	Packer	6	1
Total			**124**	**40**

NOTES:
- Each of the BOP stack pulls identified only in WAR are included in this table as both a BOP stack pull and an in-operation event.
- The component labeled unknown represents a BOP stack pull event identified in WAR data.

SOURCE: U.S. DOT, BTS, SafeOCS Program.

Investigation and Analysis

SafeOCS categorizes investigation and failure analysis (I&A) into three levels: cause immediately known (performed by the rig subsea engineer), subject matter expert (SME) review (performed by more than one subsea engineer), and root cause failure analysis (RCFA) (carried out by the OEM and/or a qualified third-party).[18] For most events, the root cause is immediately known through visual inspection, and the component can be disposed of, repaired, or replaced. For the remaining events, further investigation is expected to determine the root cause.

Table 13 summarizes the findings for 18 I&As that included recommended preventive actions and were associated with 2022 events (each row may represent more than one I&A). The I&As include three formal RCFAs, one SME review, and the remainder were for events with immediately known causes. Most of the events represented in Table 13 occurred while not in operation (46 of 51 events in 2022). Each row also shows the total reported events from 2017 to 2022 associated with that component issue. The reported causes for the failures were design issue (four I&As), QA/QC manufacturing (three), procedural error (three), wear and tear (three), and maintenance error (two).

Row eight represents events associated with nickel leaching from the use of demineralized water in BOP control fluid systems. Nickel leaching events declined from 2020 to 2021 and remained at a similar level in 2022.

[18] For I&As at the SME review level, the SMEs referred to are those who performed the investigation and are employed in the industry. The term does not refer to SMEs retained by SafeOCS.

Table 13: Findings from I&As for Subsea System Events, 2022

	REPORTED ROOT CAUSE	ROOT CAUSE DETAILS	RECOMMENDED PREVENTIVE ACTION	TOTAL EVENTS SINCE 2017	2022 EVENTS
1	Design Issue	A choke and kill valve operator seal failed due a rolled o-ring more than five years after installation.	The equipment owner will continue to update components with the latest OEM seal design (T-seal).	9	1
2	Design Issue	The design allowed debris to cause inaccurate indication on three pressure transducers on the same rig on the same day.	Hydrostatic sensors are currently tested as per the equipment owner's pre-deployment checklist, and they will now also be tested as part of post-retrieval checklist.	3	3
3	Design Issue	The failure of two pilot operated check valves (POCV) prevented operation of six choke and kill valves. The investigation concluded that both a design issue and wear and tear contributed to the failures 15 months after installation.	The equipment owner to install upgraded POCV conversion kit.	2	2
4	Design Issue	A riser running tool recently rebuilt by the OEM had paint chips bridging the seal and causing leakage.	OEM to make design changes to the seals and wear band.	1	1
5	QA/QC Manufacturing	Xylan coating flaking off caused damage to the riser connector seal.	OEM to improve QA/QC process to address the Xylan coating flaking off.	1	1
6	QA/QC Manufacturing	A diverter valve actuator leaked internally two weeks after installation.	The equipment owner updated their testing plans to function these valves more times when first received to ensure that they do not fail during operations.	1	1
7	QA/QC Manufacturing	A scored rod, loose parts, and damaged operating seal were found in the shear ram preventer operator during soak testing less than 30 days after installation due to incorrect assembly.	OEM engineering is updating the bonnet assembly procedure to require in-house checking of the retainer ring and adjusting as necessary.	1	1
8	Procedural Error	Leaks of the shear-seal plates in pressure regulators and solenoid valves were reported as showing signs of nickel binder leaching. Nickel leaching is the result of the use of demineralized water in the BOP control fluid on Tungsten-Carbide seal plates that use a nickel binder.	Re-mineralizers are in the process of being recalibrated by the equipment owner to bring the hardness up to OEM Specs.	191	21
9	Procedural Error	Corrosion inside accumulators caused the bladders to be punctured in less than one year after installation.	The equipment owner's procedures were changed to include bore-scoping accumulator bottles during the rebuild process to identify any issues with corrosion.	12	12
10	Procedural Error	The RCFA concluded that the upper blind shear ram failed to seal after being opened under differential pressure.	OEM to issue a formal communication requesting that customers avoid opening the rams under differential pressure.	3	3
11	Wear and Tear	An obsolete plastic cap designed compensated chamber of unknown age leaked externally.	Equipment owner replaced subsea compensator with a new style that has a metal cap.	13	1
12	Wear and Tear	Annular operating system seal leaked internally after two years. Seals being rolled during previous assembly was also cited as a contributing factor.	Rig owner will have a discussion with rig crew on how to properly overhaul the annular.	1	1
13	Wear and Tear	After 4.9 years, wear and tear caused severe damage to a wellhead connector operating piston seal and backup rings.	Though the equipment lasted nearly 5 years and wear and tear was the cause, an ugraded design was available, so the owner replaced the worn seal with the upgraded design (T-seal).	1	1
14	Maintenance Error	An SPM valve was assembled incorrectly.	The equipment owner measured all of the SPM caps to ensure no other SPM's were incorrectly assembled.	1	1
15	Maintenance Error	Seawater ingress lead to piston corrosion, which caused a regulator seal failure.	The equipment owner's maintenance routine will be changed to 360 days to prevent this issue in the future.	1	1

SOURCE: U.S. DOT, BTS, SafeOCS Program.

CHAPTER 3: SURFACE WCE SYSTEM EVENTS

From 2017 to 2022, 380 surface WCE system events were reported to SafeOCS, averaging 63.3 events per year as shown in Table 14. The number of events was about the same in 2022 as in 2021, but surface system reporting has generally followed a downward trend over the five-year period (see Appendix C Table 24). Adjusting for well activity levels, the event rate declined 55.4 percent from 2017 to 2022.

Events were relatively evenly split between operational states during the six-year period, with 51.3 percent of surface system events detected while in operation and 48.7 percent while not in operation. Due to greater accessibility of equipment on surface systems as compared to subsea systems, components are often not changed out until an issue

Table 14: Surface System Numbers at a Glance, 2017–2022

MEASURE	2022	2017-2022 Total	2017-2022 Average
WELLS			
Wells with Activity	139	716	160.2
Wells Spudded	62	387	64.5
RIGS			
Rigs with Activity	19	41	25.0
Rigs with Reported Events	11	32	13.3
OPERATORS			
Active Operators	16	29	18.2
Reporting Operators	6	12	8.2
BOP DAYS			
Total BOP Days	4,322	31,200	5,200
Not-in-Operation BOP Days	1,259	8,645	1,441
In-Operation BOP Days	3,064	22,555	3,759
COMPONENT EVENTS			
Total Events Reported	43	376	62.7
Overall Event Rate	9.9	12.1	11.8
Not-in-Operation Events	15	181	30.2
Not-in-Operation Event Rate	11.9	20.9	19.9
Not-in-Operation Events per Well	0.1	0.3	0.2
In-Operation Events	28	195	32.5
In-Operation Event Rate	9.1	8.6	8.7
In-Operation Events per Well	0.2	0.3	0.2
BOP STACK MOVEMENTS			
Total Stack Starts	152	1,080	180.0
Successful Starts	144	1,015	169.2
Stack Pulls	14*	96	16.0
LOC EVENTS			
Loss of Containment Events	0	0	NA

KEY: In-operation Not-in-operation

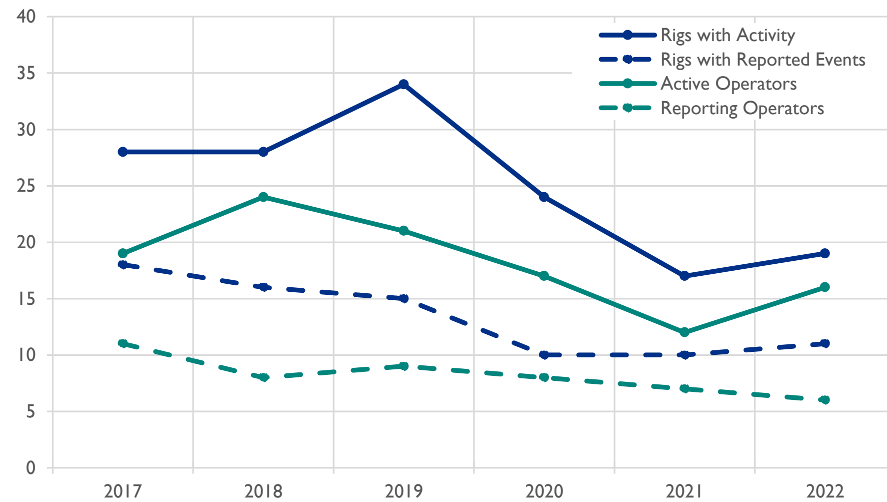
NOTES:
- Event rate is the number of events that occurred per 1,000 BOP days.
- The 2017–22 totals for rigs, operators, and wells with activity measures represent the number of unique entities.
- * Includes some BOP stack pulls identified in WAR. Table 2 provides counts. These are not included in *Total Events Reported*.

SOURCE: U.S. DOT, BTS, SafeOCS Program.

occurs, even if that is during operations. This results in a higher percentage of failures seen while in operation as compared to subsea systems. Overall, 96 BOP stack pulls were recorded from 2017 to 2022. About 9.5 percent of successful surface BOP stack starts—meaning the BOP stack was assembled on the wellhead and went into operation—eventually led to a BOP stack pull during the six-year period.

Event Reporting Levels

Figure 6: Reporting and Activity Levels for Surface Systems, 2017–22



SOURCE: U.S. DOT, BTS, SafeOCS Program.

As shown in Figure 6, changes in the number of active operators and active rigs are generally greater from year to year than corresponding changes to the number of reporting operators and rigs with reported events. The direction of change from year to year is mostly consistent between active and reporting operators and rigs, except for differing directions of change from 2017 to 2018 for operators and 2018 to 2019 for rigs. This suggests that other factors in addition to activity levels may contribute to changes in event reporting. In 2022, active operators, rigs with activity, and rigs with reported events all increased, while the number of reporting operators decreased.

Frequently Reported Components

From 2017 to 2022, 49 different components were reported as having failed on surface WCE systems. The most frequently reported components were packing elements, ram block seals, accumulators, gate valve hardware, choke and kill valves, general hardware, and regulators, each contributing at least 5.0 percent of events and together comprising 56.1 percent of all surface system events.

Figure 7 illustrates each reported component's percentage of events over the six-year period compared to that component's percentage of the typical population on a rig with a surface BOP stack. The orange (not in operation) and blue (in operation) stacked bars together show the component's percentage of total subsea events, and the wider light blue bars show each component's percentage of the typical component population.

All else being equal, one could expect a component's percentage of events to be consistent with its percentage of the population; however, as shown on the figure, that is not the case for most components.[19] A ratio less than 1.0 indicates that this component experienced a lower percentage of failures compared to its percentage of the population. For surface systems, very few components have a failure ratio less than one, which can potentially be influenced by a long service life expectancy for those components. As shown in Figure 7, valve gate/seat, ram cavity, and pressure switches are such examples.

A failure ratio greater than 1.0 indicates that other factors are influencing the number of failures (e.g., frequency of use, circuit complexity, operating environment, and installation and maintenance practices). Packing elements, ram block seals, and choke and kill valves each had a failure ratio[20] greater than 1.0, meaning they had a disproportionately high number of reports as compared to their population, relative to other components. Hardware and regulators are also two components with high failure ratios. The following provides a brief discussion of selected components:

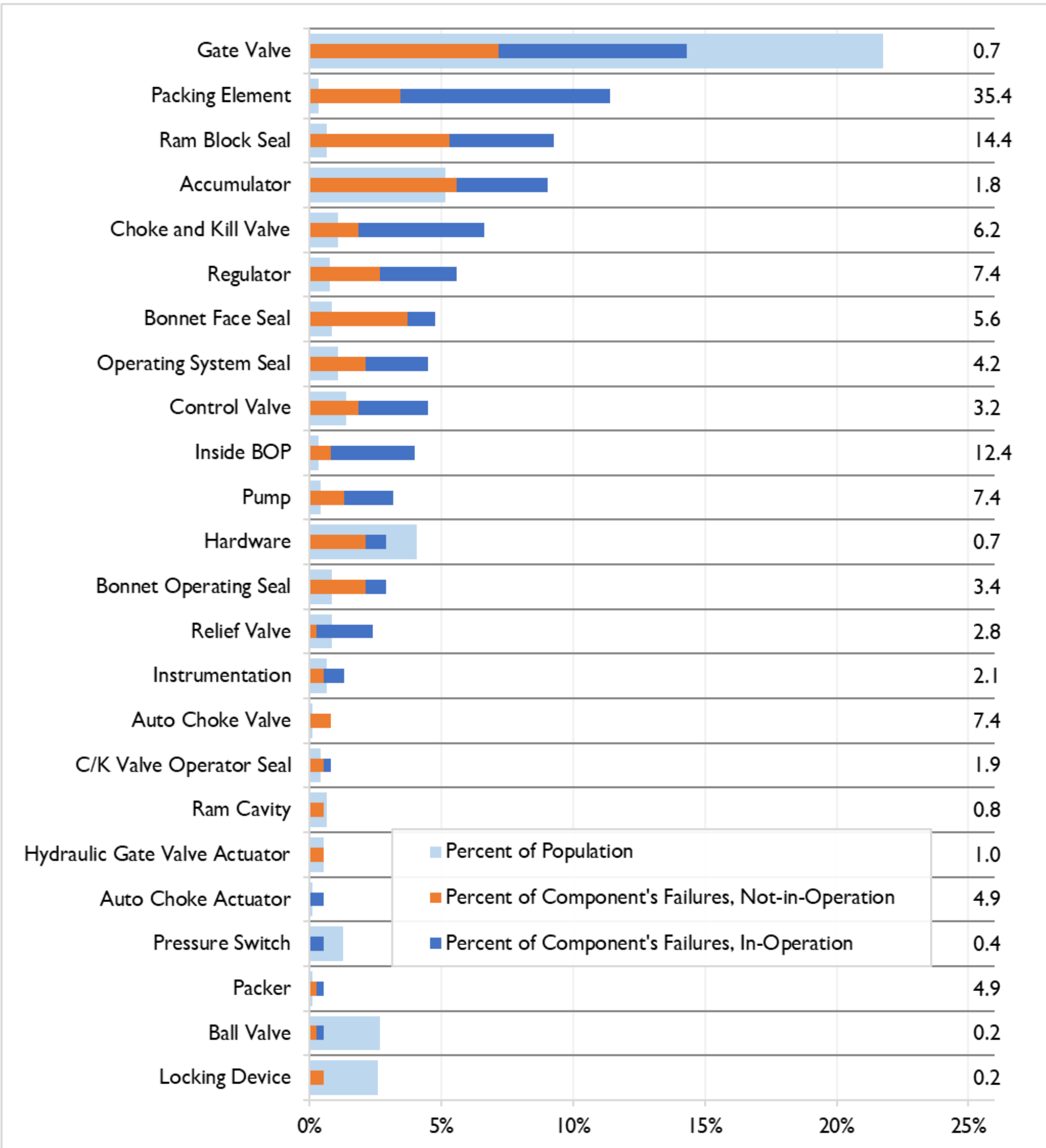
- *Annular packing elements and ram block seals:* The frequency of failure for these component types may be partially explained by the fact they are consumable seal types which are easily accessible even during operations. Therefore, they are often run until they do not pass a test, rather than being more proactively replaced.
- *Accumulators:* Accumulators on surface systems are located on deck where they are easily accessible, and similar to subsea systems, regulation requires that they are arranged in banks where no one bank can contain more than 25.0 percent of the total

[19] Component estimates are provided in the SafeOCS supplement, *WCE Estimated System Component Counts*, published separately.

[20] Ratio = a component's percent of failures divided by that component's percent of the population.

accumulator system capacity.[21] This allows for one bank of accumulators at a time to be isolated for maintenance. Accumulator bladders can therefore be run to failure and replaced individually as required without risk to the system.

Figure 7: Surface System Component Failures Relative to Component Population, 2017-22



NOTE: Components with 0.5 percent or less of failures are excluded and total 6.7 percent of all surface system failures. Piping/tubing (1.3 percent of failures) is not represented in the table as it does not have an estimated population average. Failure ratio, shown in righthand column, represents the component's percent of failures divided by that component's percent of the population.

SOURCE: U.S. DOT, BTS, SafeOCS Program.

[21] API Standard 53 (4th ed.), incorporated by reference at 30 CFR 250.198.

Failure Types

Similar to subsea systems, most events from 2017 to 2022 on surface systems were a type of leak, comprising 81.7 percent of events (Table 15). However, in contrast to subsea systems, internal leaks were more common than external leaks on surface systems over the six-year period. This is due to the disparity in population and nature of the components, as the control valves used on surface systems are closed-hydraulic, whereas those on subsea systems are vent-to-atmosphere.

Table 15: Failure Types of Surface System Events, 2017–2022

FAILURE TYPE	2017 (n=110)	2018 (n=69)	2019 (n=87)	2020 (n=21)	2021 (n=46)	2022 (n=43)	Total (n=376)
LEAKS							
External Leak	30.9%	34.8%	39.1%	61.9%	23.9%	32.6%	34.6%
Internal Leak	49.1%	49.3%	40.2%	14.3%	63.0%	51.2%	47.1%
OTHER							
Communication / Signal Issue	0.0%	2.9%	3.4%	0.0%	0.0%	0.0%	1.3%
Electrical Issue	0.0%	2.9%	0.0%	4.8%	0.0%	0.0%	0.8%
Fail to Function on Command	2.7%	2.9%	4.6%	4.8%	4.3%	4.7%	3.2%
Inaccurate Indication	0.0%	0.0%	1.1%	0.0%	0.0%	0.0%	0.3%
Mechanical Issue	14.5%	2.9%	6.9%	9.5%	4.3%	4.7%	8.0%
Process Issue	2.7%	4.3%	3.4%	0.0%	2.2%	4.7%	3.7%
Unintended Operation	0.0%	0.0%	0.0%	4.8%	0.0%	0.0%	0.3%
Other	0.0%	0.0%	1.1%	0.0%	2.2%	2.3%	0.8%
TOTALS	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

SOURCE: U.S. DOT, BTS, SafeOCS Program.

Component types with the most internal leaks from 2017 to 2022 include annular packing elements, ram block seals, and gate valve hardware. Component types with the most external leaks include accumulators, bonnet face seals, regulators, and bonnet operating seals. For choke and kill valves, the most frequent failure types are both internal and external leaks, and for hardware, the most frequent failure types are internal leaks and mechanical issues.

Detection Methods

Most surface system leaks from 2017 to 2022 (51.3 percent) were detected through pressure testing, with a similar distribution of detection methods between in-operation and not-in-operation events. As shown in Table 16, an anomalous year to this trend was 2020, where only 14.3 percent of events were found via pressure testing. A low number of reports were received that year overall. Interestingly, in 2022, events were found by the lowest variety of detection methods (four) since 2017, with events found only via pressure testing, function testing, casual observation, and inspection. For the most frequently reported components, the majority of events were found through pressure testing, apart from accumulators and regulators, which were identified most frequently through casual observation and inspection.

Table 16: Detection Methods for Surface System Events, 2017–2022

	DETECTION METHOD	2017 (n=110)	2018 (n=69)	2019 (n=87)	2020 (n=21)	2021 (n=46)	2022 (n=43)	Total (n=337)
	Casual Observation	14.5%	7.2%	11.5%	33.3%	13.0%	16.3%	13.6%
	Continuous Condition Monitoring	11.8%	5.8%	3.4%	4.8%	4.3%	0.0%	6.1%
	On Demand	1.8%	0.0%	0.0%	0.0%	4.3%	0.0%	1.1%
	Periodic Condition Monitoring	1.8%	0.0%	1.1%	4.8%	0.0%	0.0%	1.1%
MIT	Corrective Maintenance	0.0%	0.0%	4.6%	0.0%	0.0%	0.0%	1.1%
	Periodic Maintenance	0.0%	0.0%	4.6%	9.5%	0.0%	0.0%	1.6%
	Inspection	4.5%	7.2%	16.1%	9.5%	8.7%	7.0%	8.8%
	Function Testing	10.9%	15.9%	13.8%	23.8%	19.6%	20.9%	15.4%
	Pressure Testing	54.5%	63.8%	44.8%	14.3%	50.0%	55.8%	51.3%

SOURCE: U.S. DOT, BTS, SafeOCS Program.

Root Causes of Events

As with subsea systems, most surface system events from 2017 to 2022 (61.2 percent) were attributed to wear and tear. As shown in Table 17, the percentage of surface system events attributed to wear and tear increased in more recent years. Detailed review of notifications indicates that, similar to subsea events, the submitted information does not always provide adequate support for a root cause of wear and tear. Additionally, it may be difficult to know the details of wear and tear cases on surface systems, as WCE components such as annular preventers are often sent to shore for major maintenance.

Table 17: Root Causes of Surface System Events, 2017–2022

REPORTED ROOT CAUSE	2017 (n=110)	2018 (n=69)	2019 (n=87)	2020 (n=21)	2021 (n=46)	2022 (n=43)	Total (n=337)
Design Issue	3.6%	7.2%	2.3%	0.0%	0.0%	7.0%	3.7%
QA/QC Manufacturing	3.6%	4.3%	5.7%	0.0%	6.5%	4.7%	4.5%
Maintenance Error	2.7%	7.2%	14.9%	0.0%	0.0%	2.3%	5.9%
Procedural Error	1.8%	1.4%	3.4%	0.0%	2.2%	0.0%	1.9%
Wear and Tear	48.2%	58.0%	48.3%	90.5%	89.1%	81.4%	61.2%
Other	7.3%	1.4%	4.6%	9.5%	0.0%	0.0%	4.0%
NOT DETERMINED							
Inconclusive	0.9%	1.4%	2.3%	0.0%	0.0%	0.0%	1.1%
Assessment Pending	5.5%	8.7%	2.3%	0.0%	2.2%	4.7%	4.5%
Not Reported	26.4%	10.1%	16.1%	0.0%	0.0%	0.0%	13.3%
TOTALS	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

SOURCE: U.S. DOT, BTS, SafeOCS Program.

Wear and tear was also the top root cause for failures of frequently reported components from 2017 to 2022, shown in Table 18. In addition to wear and tear, commonly reported root causes for component events include maintenance error for ram block seals and design issue for accumulators. As with subsea, supporting information for failures attributed to design issue has been infrequent.

Table 18: Root Causes of Frequently Reported Components for Surface Systems, 2017–2022

REPORTED ROOT CAUSE	Packing Element	Accumulator	Ram Block Seal	Choke and Kill Valve	Regulator	Hardware	Gate Valve Hardware
Design Issue	4.7%	14.7%	2.9%	0.0%	0.0%	0.0%	4.8%
QA/QC Manufacturing	2.3%	0.0%	5.9%	3.2%	4.0%	0.0%	4.8%
Maintenance Error	2.3%	2.9%	29.4%	3.2%	8.0%	0.0%	4.8%
Procedural Error	0.0%	2.9%	0.0%	0.0%	0.0%	0.0%	0.0%
Wear and Tear	69.8%	64.7%	47.1%	41.9%	60.0%	95.7%	76.2%
Other	2.3%	0.0%	0.0%	12.9%	8.0%	0.0%	0.0%
NOT DETERMINED							
Inconclusive	0.0%	0.0%	0.0%	3.2%	4.0%	0.0%	4.8%
Assessment Pending	4.7%	11.8%	2.9%	0.0%	0.0%	4.3%	0.0%
Not Reported	14.0%	2.9%	11.8%	35.5%	16.0%	0.0%	4.8%

SOURCE: U.S. DOT, BTS, SafeOCS Program.

In-Operation Events Including BOP Stack Pulls

From 2017 to 2022, a total of 195 in-operation events were reported for surface WCE systems, including 60 BOP stack pulls. An additional 36 BOP stack pulls were identified in WAR data. When adjusted for the level of activity, an average of 8.7 events occurred per thousand in-operation BOP days over the six-year period.

Table 19 shows the equipment involved in events leading to surface BOP stack pulls from 2017 to 2022, as well as the total number of in-operation events for those component combinations. Of the 12 different component types associated with surface BOP stack pulls, annular packing elements have been associated with the most (49), followed by ram block seals (15), operating system seals (seven), and bonnet operating seals (six). The similarities in the numbers of total in-operation events as compared to BOP stack pulls for many component combinations means that the failed component needed to be repaired or replaced.

Each of the events involving annular packing elements failing to hold pressure (i.e., an internal leak) was observed during a periodic BOP stack test designed to confirm the BOP equipment's integrity. The data suggests that surface system operators often replace annular packing elements only after they have failed a pressure test.

From 2017 to 2022, 87 BOP stack pulls involved a type of leak, including 35 of the 36 identified in WAR data. For the 60 BOP stack pulls reported to SafeOCS from 2017 to 2022, 36 cited a root cause of wear and tear. Of the remaining 24, 13 either did not cite a root cause or selected "other" and offered a description such as "damage from ram block" or "bad element." The remaining 10 listed a variety of root causes such as QA/QC manufacturing or design issue. For the BOP stack pulls identified in WAR data, there is typically insufficient detail available to discern the root cause.

In 2022, six surface BOP stack pulls were reported to SafeOCS and an additional eight surface BOP stack pulls were identified in WAR data. These included seven failures of annular packing elements on the annular preventer, four failures of bonnet operating seals or bonnet face seals on the pipe ram preventer, and two failures of a ram block seal and one of ram block hardware on the shear ram preventer. Most of these failures involved leaks.

Table 19: Component Combinations of Surface BOP Stack Pulls, 2017–2022

Subunit	Item	Component	2017-2022 In-Operation Events	2017-2022 Stack Pulls
BOP Controls	BOP Control Panel	Central Control Console	1	1
		Instrumentation	2	1
	HPU Mix System	Regulator	2	1
		Selector Manipulator Valve	6	2
	Surface Control System	Regulator	9	2
BOP Stack	Annular Preventer	Hardware_all other Mechanical Elements	1	1
		Operating System Seal	9	7
		Packing Element	53	49
	Pipe Ram Preventer	Bonnet Face Seal	5	3
		Bonnet Operating Seal	2	2
		Bonnet Seal	1	1
		Ram Block Seal	7	5
	Shear Ram Preventer	Bonnet Face Seal	2	2
		Bonnet Operating Seal	5	4
		Hardware_all other Mechanical Elements	2	2
		Ram Block Hardware	1	1
		Ram Block Seal	10	10
		Unknown	1	1
Riser System	Riser	Flange	1	1
Total			**120**	**96**

NOTES:
- Each of the BOP stack pulls identified only in WAR are included in this table as both a BOP stack pull and an in-operation event.
- The component labeled unknown represents a BOP stack pull event identified in WAR data.

SOURCE: U.S. DOT, BTS, SafeOCS Program.

Investigation and Analysis

I&A information was received for 17 of the 43 surface system events in 2022. The I&As included one at the RCFA level and 12 for events with immediately known causes. Table 20 summarizes the findings for the one I&A (at the RCFA level) that included a recommended preventive action.

Table 20: Findings from I&As for Surface System Events, 2022

	REPORTED ROOT CAUSE	ROOT CAUSE DETAILS	RECOMMENDED PREVENTIVE ACTION	TOTAL EVENTS SINCE 2017	2022 EVENTS
1	Design Issue	The redesign to use extra rubber in shear ram preventer side packer failed to consider all metal tolerance conditions.	OEM redesigned the side packers of the ram to accommodate max tolerance conditions.	1	1

SOURCE: U.S. DOT, BTS, SafeOCS Program.

CHAPTER 4: TOPICS OF INTEREST

Intervention Equipment Failures

After a well has been drilled and completed, there may be occasions when that well will require maintenance, repair, or replacement. This type of work is referred to as a workover or intervention operation and may be performed using a non-drilling intervention vessel or may require a drilling rig, depending on the specifics\ work required.

The SafeOCS database was originally designed for capturing specifics of subsea WCE component events, and later modified to include surface offshore WCE system component events. This modification was a relatively straightforward task due to the design standards being the same – API Specification16A. Although SafeOCS has received reports for events involving intervention equipment components, the equipment structure (sub-unit, item, and component) is different from subsea and surface offshore WCE systems, requiring a different database form structure, which has not yet been established. Nonetheless, some summary of the events is possible, which is included below.[22]

As shown in Figure 8, from 2017 to 2022, SafeOCS received 217 event notifications involving intervention equipment. Although no failures were reported to SafeOCS in 2018, the activity in WAR data for intervention vessels was similar to other years. From 2019 to 2022, the number of reports trended downward, similar to the rig WCE failure reports.

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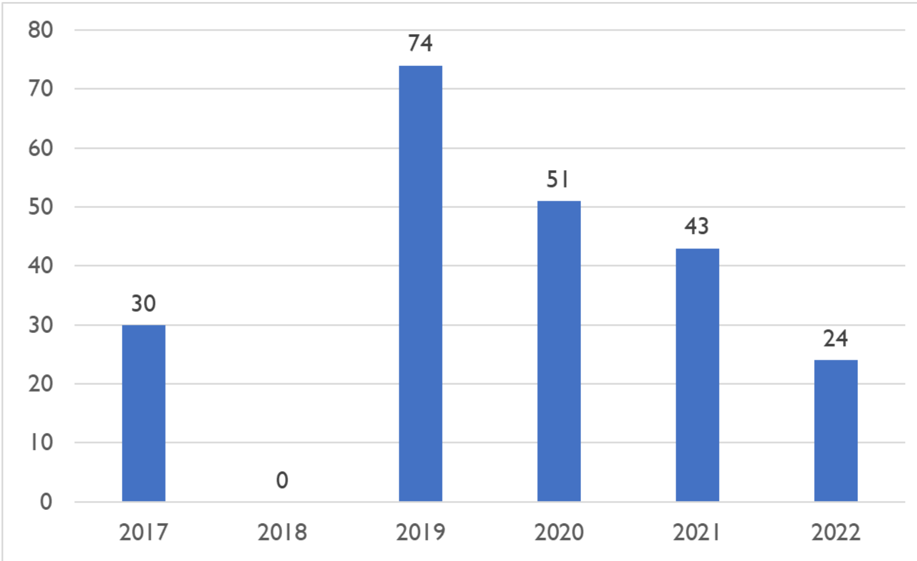
[22] The following API standards for subsea well intervention equipment informed the analysis presented in this section:

- API Standard 17G, Design and Manufacture of Subsea Well Intervention Equipment, Third Edition, Nov. 2019. Openwater intervention riser system (OWIRS) incorporates the use of a surface test tree and BOP assembly to access the wellbore/subsea tree. Through-BOP intervention riser system (TBIRS) incorporates the use of a subsea test tree inside of a subsea drilling BOP to access the wellbore/subsea tree.
- API Recommended Practice 17G5, Subsea Intervention Workover Control , First Edition, Nov. 2019.

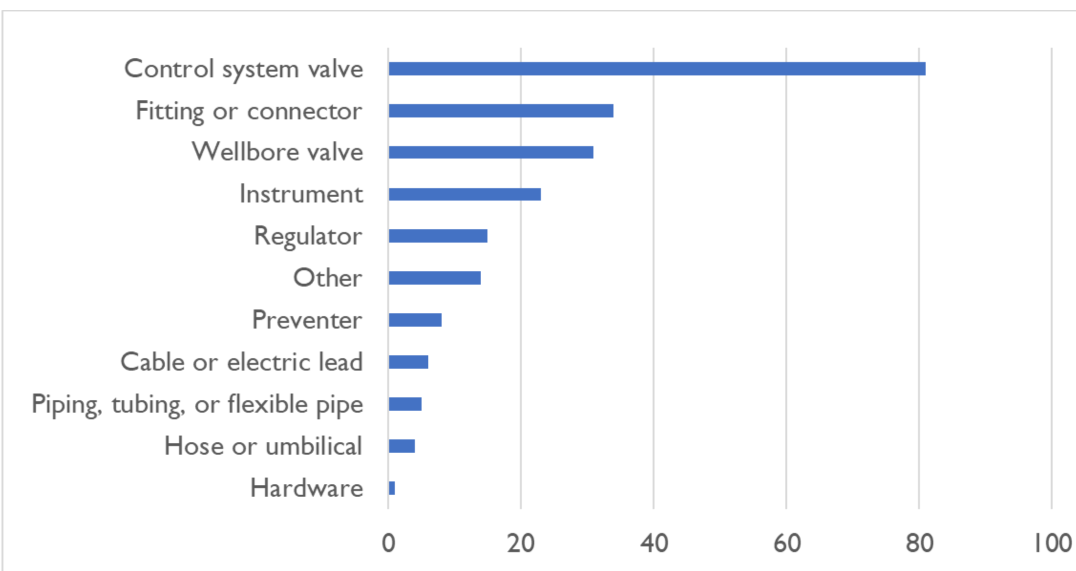
Figure 8: Intervention System Events, 2017-2022



SOURCE: U.S. DOT, BTS, SafeOCS Program.

Using generic categories for the components established by SafeOCS SMEs, the following breakdown shows that failures across the six years are mostly on control system valves and valves that access the wellbore fluids. The next highest groups are fittings/connections, instruments, and regulators.

Figure 9: Components Involved in Intervention Systems Events, 2017-2022



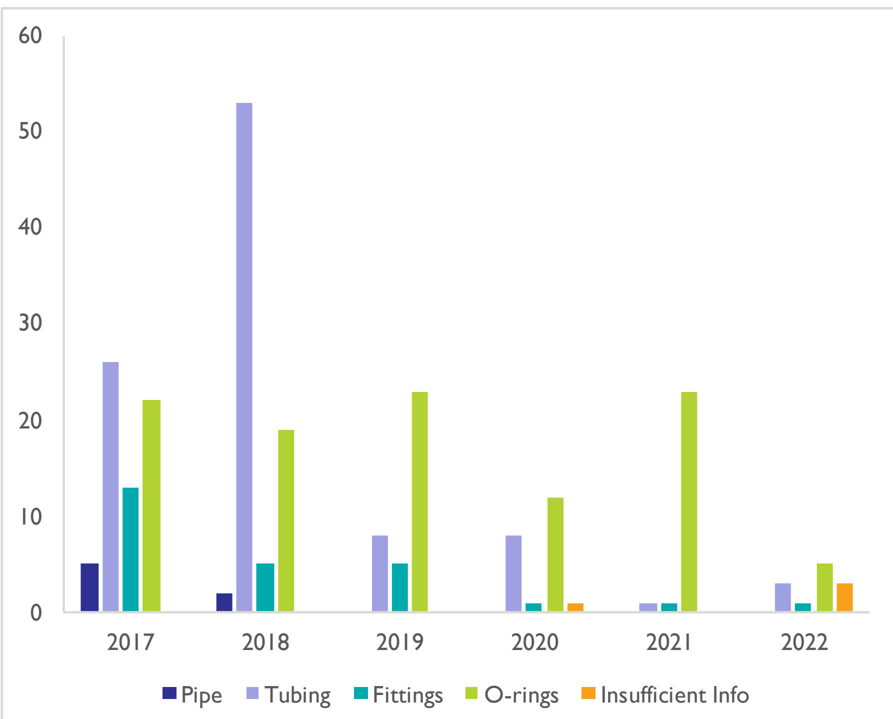
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Next steps for the evaluation of intervention system events could include enhancements to the database structure to support a more robust collection and analysis, as well as compiling denominator data to contextualize events as is done for subsea and surface WCE events.

Piping/Tubing Events

This section offers a more in-depth review of piping/tubing events reported to SafeOCS during 2017 to 2022. Piping/tubing events were examined for notable observations and potential trends due to both their prevalence in reported events and because the characteristics of piping/tubing components reported can vary widely. Figure 10 illustrates the different types of these events reported over the 2017 to 2022 period.

Figure 10: Piping/Tubing Events, 2017-2022



SOURCE: U.S. DOT, BTS, SafeOCS Program.

Piping and tubing are installed during the initial assembly of the equipment, and they are replaced only when they are damaged or found leaking. Life expectancy is usually considered the life of the system and as such, there are limited preventive maintenance routines beyond initial verification at installation or after being reconnected. Piping, tubing, (and fittings) are listed for 241 notifications from 2017 to 2022, with 15 occurring in 2022 (12 for subsea systems and three for surface). However, this component is comprised of many types of subcomponents. For this analysis, the various types of piping and tubing parts were grouped as shown in Table 21.

Elastomeric seals were listed as the specific part that failed in 43.3 percent of these cases, and 44.2 percent were specifically failures of the actual piping or tubing (rather than the variety of subcomponents) parts. Thirty-two of the piping / tubing events (13.3 percent) were of pieces of tubing that had not been deburred by the manufacturer; this was noticed upon inspection on the rig and they were replaced before going into use. Thirty-one reports (12.9 percent) refer to tubing fittings that had been over-swaged and discovered when being checked with a go/no-go gauge during inspection. Fifteen cases (6.5 percent) involved NPT thread issues. The remaining cases are predominantly failures of adaptor fittings and o-rings. The o-ring failures are associated with six different parts: code-62 flanges, pipe unions, pod stabs, SAE pipe fittings, clamp hubs, and seal subs. Together these account for 103 (42.9 percent) of the total.

The above seals are classified as static and are not designed to move after installation. Static seals are assembled into the hardware (e.g., a code-62 flange) and the seal (o-ring) in that flange is "squeezed" by tightening the flange bolts to the recommended torque. This tightening procedure provides the necessary energizing force to contain the pressurized BOP control fluid. Should the bolts be under-torqued or vibrate loose in service, then the static seal may lose its required squeeze and leak. Code-62 flange o-rings leak when the flange bolts have not been correctly torqued at installation, and SAE fitting o-rings tend to leak when the backup nut has not been tightened after the direction of the fitting has been changed. While the number of reported code-62 flange o-ring leaks and SAE fitting o-ring failures had high total reported events compared to other types of piping/tubing over the six-year period (29 and 61 events, respectively), which may be due to maintenance or assembly issues, failures of these types tended to decrease over time, with only four such issues reported in 2022.

Table 21: Piping/Tubing Events, 2017-2022

Group	Type	2017	2018	2019	2020	2021	2022	Total	Group Total
Piping	Flange	1	-	-	-	-	-	1	7
	Pipe	4	2	-	-	-	-	6	
Tubing	Tubing	2	32	4	2	1	1	42	99
	Tubing Fitting	24	21	4	6	-	2	57	
Fittings	Autoclave	3	1	-	-	-	-	4	26
	JIC Flare	2	-	2	-	-	-	4	
	Threaded (NPT)	8	3	3	-	1	1	16	
	Pressure Snubber	-	1	-	1	-	-	2	
O-rings	Clamp Hub	-	-	1	-	-	-	1	104
	Pod Stab	1	-	-	-	-	-	1	
	Union	1	3	-	1	-	-	5	
	Seal Sub	-	-	3	2	1	1	7	
	Code 62 Flange	6	3	9	2	6	3	29	
	SAE Fitting	14	13	10	7	16	1	61	
Other	Insufficient Info	-	-	-	1	-	3	4	4
Total		**66**	**79**	**36**	**22**	**25**	**12**	**240**	**240**

NOTE: Dash indicates a count of zero.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

APPENDIX A: REGULATORY REPORTING REQUIREMENT

The failure reporting requirement is codified in 30 CFR 250.730(c) of BSEE's well control rule, which went into effect on July 28, 2016. In 2019, BSEE revised the reporting rule to clarify that event notifications and reports must be sent to BTS as BSEE's designated third party.[23] The rule follows ("you" refers to lessees and designated operators):

> (c) You must follow the failure reporting procedures contained in API Standard 53, (incorporated by reference in §250.198), and:
>
>> (1) You must provide a written notice of equipment failure to the Chief, Office of Offshore Regulatory Programs (OORP), unless BSEE has designated a third party as provided in paragraph (c)(4) of this section, and the manufacturer of such equipment within 30 days after the discovery and identification of the failure. A failure is any condition that prevents the equipment from meeting the functional specification.
>>
>> (2) You must ensure that an investigation and a failure analysis are started within 120 days of the failure to determine the cause and are completed within 120 days upon starting the investigation and failure analysis. You must also ensure that the results and any corrective action are documented. You must ensure that the analysis report is submitted to the Chief OORP, unless BSEE has designated a third party as provided in paragraph (c)(4) of this section, as well as the manufacturer. If you cannot complete the investigation and analysis within the specified time, you must submit an extension request detailing how you will complete the investigation and analysis to BSEE for approval. You must submit the extension request to the Chief, OORP.
>>
>> (3) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such changes, report the

[23] 84 Fed. Reg. 21,908 (May 15, 2019).

design change or modified procedures in writing to the Chief OORP, unless BSEE has designated a third party as provided in paragraph (c)(4) of this section.

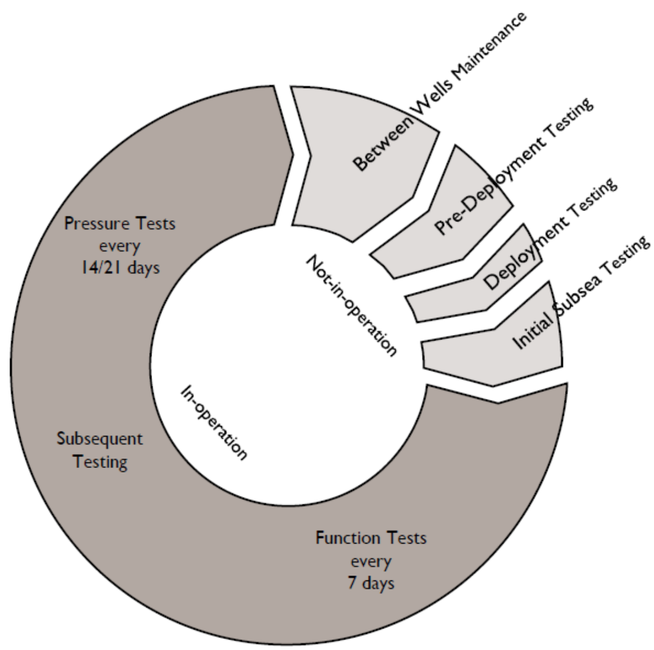
(4) Submit notices and reports to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, Virginia 20166. BSEE may designate a third party to receive the data and reports on behalf of BSEE. If BSEE designates a third party, you must submit the data and reports to the designated third party.

Appendix B: Operational States of WCE Systems

This appendix separates events into two states, where applicable, based on when the event occurred: *in operation* or *not in operation*. This section provides an overview of these states and the various phases within them to provide additional context for failure events. Figure 11 provides a visual representation for subsea WCE systems.

An event is classified as not in operation if it occurred or was discovered during maintenance, inspection, and testing (MIT) or other preparatory work, and in operation if it occurred or was discovered after the equipment had been successfully tested and put into service. All WCE needs to be reliably available while in operation; to meet this requirement, systems are often designed with redundant components or subsystems.

Figure 11: The Cycle of Maintenance, Inspection, and Testing



KEY: In-operation Not-in-operation
NOTE: The figure illustrates the cyclical MIT regime practiced on subsea WCE systems, scaled to show the approximate time split for an average new well.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

It is important to recognize that WCE systems provide secondary well control; the primary well control is fluid management or ensuring that the hydrostatic pressure of the mud in the well is always at least equal to formation pressure. On many wells, the only time that the well control equipment is ever used is when it is being tested. Ensuring that equipment is readily available and correctly functions when needed during operations involves a detailed and cyclical MIT regime, which mainly occurs while the BOP stack is not in operation. BSEE regulations modify MIT requirements, including those of

API Standard 53.[24] The remainder of this section includes a discussion of time-based versus condition-based maintenance practices, followed by more detail about each phase of MIT.

Condition-Based Maintenance

An alternative to time-based maintenance schedules is condition- or performance-based maintenance. Instead of components having fixed maintenance periods, such as between wells, annually, or every 30 months, equipment owners utilize condition monitoring data to determine when maintenance is required. Developments in recent years have enhanced the instrumentation of WCE systems, particularly in the BOP control systems, facilitating the collection and monitoring of condition data. An example of condition-based maintenance is signature testing, where pressure and current requirements for various systems are accurately measured when new, and then subsequent measurements of those components are compared to determine when maintenance is required.

Certain component types, sometimes referred to as consumables, have typically followed condition-based maintenance. The life expectancy of a ram packer or annual packer, for example, which creates a seal around the pipe or annulus, is difficult to forecast due to the changes in the operational environment during use. A visual inspection determines whether the component is replaced, regardless of time in use, other than upon failure. Fixed maintenance periods can result in invasive maintenance practices for some component types. For example, seals are to be replaced every time they are exposed, which may introduce the potential for maintenance errors.

MIT for Subsea WCE Systems

MIT While Not in Operation

Any events that occur during the following four phases can be resolved before the BOP goes into operation, decreasing the likelihood of an event with safety or environmental consequences.

[24] 30 CFR 250.737, 250.739.

- **Between Wells Maintenance (BWM):** This is the period between one well construction finishing and the next well construction starting. As the BOP stack is being recovered from the well, MIT commences on the equipment as it becomes accessible (e.g., telescopic joint, riser, choke manifold, surface mounted control equipment). When the BOP stack is safely on deck, BWM procedures and usually some other periodic maintenance, such as annual and five-yearly procedures, are carried out. During the scheduled BWM periods, all efforts are focused on finding and resolving any potential issues before the next well construction begins. This detailed attention to components results in the most not-in-operation event notifications compared to other MIT phases.

- **Pre-Deployment Testing:** This is the minimum required testing that must be carried out before the WCE systems can be deployed subsea. It takes place on the rig before the BOP stack is lowered into the water. Pre-deployment testing includes operating every BOP stack function from every control panel and through each control pod. It also includes pressure testing every barrier to a pressure higher than it may see on the upcoming well. Although the API S53 pre-deployment testing is typically completed with the BOP stack on the test stump in the set-back area, events discovered while moving the BOP stack to the moonpool are also categorized as occurring during this phase.

- **Deployment Testing:** Pressure tests of the riser mounted choke and kill line sections, which provide fluid pressure control and allow drilling or wellbore fluids to be evacuated from the well safely if needed, are carried out during BOP stack deployment. Control system pressures, temperatures, currents, angles, and other data received from the control pods are continuously monitored, even during this phase. Additional detail is provided in the discussion of the riser system in the SafeOCS supplement, *WCE Subunit Boundaries*, published separately.

- **Initial Subsea Testing:** This is the first time on a well that the complete system, including the wellhead connection, is pressure and function tested. These tests must be carried out before any well operations take place. If any issues are detected, the wellhead connector can be unlatched from the wellhead to retrieve the BOP stack to the surface for resolution before the commencement of operations.

MIT During Operations: Subsequent Testing

Subsequent testing regimes take place while the BOP stack is in operation. Every seven days,[25] all the non-latching equipment[26] is function tested; all rams, annulars, and valves are closed and opened to confirm that they can operate if required. Every 14 days,[27] all pipe rams, annulars, valves, and the choke manifold are pressure tested. Every 21 days, the acoustic batteries are checked,[28] and the shear rams are pressure-tested.[29] Suppose the BOP stack remains subsea for long periods. In that case, every 90 days, the high-pressure shear circuit(s) are tested. Every 180 days, the accumulators (both surface and subsea) are subjected to drawdown tests to confirm that the required volumes of pressurized BOP control fluid are available.[30] If the BOP stack is not subsea long enough for these tests to become due, then the pre-deployment testing for the next well will include them.

MIT for Surface WCE Systems

As with subsea WCE systems, an event is classified as not in operation if it occurred or was discovered during MIT or other preparatory work, and in operation if it occurred or was discovered after the equipment had been successfully tested and put into service. A surface WCE system is in operation once the BOP stack has been assembled on the wellhead and all the initial testing has been completed.

MIT While Not in Operation

Many surface BOPs are rented and maintained by third parties or maintained by the equipment owner at shore bases. When the well operation ends, and BWM is required, the equipment is

[25] 30 CFR 250.737 and API Standard 53 (4th ed.) section 7.6.5.1.1.

[26] Latching equipment, e.g., the wellhead, LMRP, and choke/kill connectors, includes the remotely operated components that cannot be tested after the initial subsea testing without compromise. Non-latching equipment is all other WCE.

[27] 30 CFR 250.737(a)(2). Some operators may utilize a 21-day test frequency if approved by BSEE. 30 CFR 250.737(a)(4).

[28] API Standard 53 (4th ed.) table 7.

[29] Shear rams are pressure tested at least every 30 days per 30 CFR 250.737(a)(2). Operators may also follow the more frequent 21-day testing per API Standard 53 (4th ed.) table 10.

[30] API Standard 53 (4th ed.) table 7.

often sent to shore for maintenance and exchange. Importantly, failure events identified onshore by third parties while the equipment is not under contract to the operator may be less likely to be reported to SafeOCS.

Since WCE on surface system rigs is accessible on deck throughout operations, and there are fewer components, the MIT conducted during BWM and before beginning operations is less intensive than for subsea WCE systems. Before beginning operations, pressure testing takes place for the rams, annulars, and valves. Initial testing is also conducted before any well operations take place.

MIT During Operations: Subsequent Testing

The basic subsequent testing regime for surface systems is similar to that of subsea systems.

APPENDIX C: YEARLY NUMBERS AT A GLANCE 2017-2022

Table 22: Yearly Numbers at a Glance, 2017–2022

MEASURE	2017	2018	2019	2020	2021	2022	2017-2022 Total	2017-2022 Average
WELLS								
Wells with Activity	325	389	397	264	243	273	1,618	315.2
Wells Spudded	147	182	165	113	103	112	822	137.0
RIGS								
Rigs with Activity	60	59	63	50	37	43	82	52.0
Rigs with Reported Events	47	40	36	32	26	31	70	35.3
OPERATORS								
Active Operators	27	32	29	27	20	24	39	26.5
Reporting Operators	18	14	13	14	12	13	25	14
BOP DAYS								
Total BOP Days	16,072	17,073	16,990	12,462	11,180	12,358	86,135	14,356
Not-in-Operation BOP Days	6,123	6,334	6,475	5,382	4,608	4,983	33,905	5,651
In-Operation BOP Days	9,949	10,739	10,515	7,080	6,572	7,375	52,230	8,705
Subsea System BOP Days	10,917	10,063	9,853	8,490	7,685	8,036	55,043	9,174
Surface System BOP Days	5,178	6,808	7,108	3,962	3,822	4,322	31,200	5,200
COMPONENT EVENTS								
Total Events Reported	1,411	1,197	995	635	411	481	5,130	855
Overall Event Rate	87.8	70.1	58.6	51.0	36.8	38.9	59.6	57.2
Not-in-Operation Events	1,214	1,055	871	568	342	396	4,446	741
In-Operation Events	197	142	124	67	69	85	684	114
Subsea System Events	1,301	1,128	908	614	365	438	4,754	792
Surface System Events	110	69	87	21	46	43	376	63
LOC EVENTS								
Loss of Containment Events	1	0	0	0	0	0	1	NA

KEY: In-operation Not-in-operation

NOTES:

- Event rate is the number of events that occurred per 1,000 BOP days.
- The 2017–22 totals for rigs, operators, and wells with activity measures represent the number of unique entities.

SOURCE: U.S. DOT, BTS, SafeOCS Program.

Table 23: Subsea System Yearly Numbers at a Glance, 2017–2022

MEASURE	2017	2018	2019	2020	2021	2022	2017-2022 Total	2017-2022 Average
WELLS								
Wells with Activity	167	173	190	142	136	134	650	157.0
Wells Spudded	86	96	79	72	52	50	435	72.5
RIGS								
Total Rigs with Activity	32	31	29	26	21	24	41	27.2
With One Subsea Stack	10	9	8	6	5	5	13	7.2
With Two Subsea Stacks	22	22	21	20	16	19	28	20.0
Rigs with Reported Events	29	24	21	22	16	20	38	22.0
OPERATORS								
Active Operators	17	16	20	19	14	15	23	16.8
Reporting Operators	11	10	10	11	10	11	20	10.5
BOP DAYS								
Total BOP Days	10,917	10,063	9,853	8,490	7,685	8,036	55,043	9,174
Not-in-Operation BOP Days	4,538	4,359	4,534	4,138	3,771	3,724	25,064	4,177
In-Operation BOP Days	6,379	5,704	5,319	4,352	3,914	4,311	29,979	4,997
COMPONENT EVENTS								
Total Events Reported	1,301	1,128	908	614	365	438	4,754	792
Overall Event Rate	119.2	112.1	92.2	72.3	47.5	54.5	86.4	83.0
Not-in-Operation Events	1,152	1,022	826	561	323	381	4,265	710.8
Not-in-Operation Event Rate	253.9	234.5	182.2	135.6	85.7	102.3	170.2	165.7
Not-in-Operation Events per Well	6.9	5.9	4.3	4.0	2.4	2.8	6.6	4.4
In-Operation Events	149	106	82	53	42	57	489	81.5
In-Operation Event Rate	23.4	18.6	15.4	12.2	10.7	13.2	16.3	15.6
In-Operation Events per Well	0.9	0.6	0.4	0.4	0.3	0.4	0.8	0.5
BOP STACK MOVEMENTS								
Total Stack Runs	203	179	220	173	145	136	1,056	176.0
Successful Runs	166	152	171	170	126	126	911	151.8
Stack Pulls	9	8	8*	7*	3*	5*	40	6.7
LOC EVENTS								
Loss of Containment Events	1	0	0	0	0	0	1	NA

KEY: In-operation Not-in-operation

NOTES:

- Event rate is the number of events that occurred per 1,000 BOP days.
- The 2017–22 totals for rigs, operators, and wells with activity measures represent the number of unique entities.

* Includes some BOP stack pulls identified in WAR. Table 2 provides counts. These are not included in *Total Events Reported*.

SOURCE: U.S. DOT, BTS, SafeOCS Program.

Table 24: Surface System Yearly Numbers at a Glance, 2017–2022

MEASURE	2017	2018	2019	2020	2021	2022	2017-2022 Total	2017-2022 Average
WELLS								
Wells with Activity	160	217	208	123	114	139	716	160.2
Wells Spudded	61	86	86	41	51	62	387	64.5
RIGS								
Rigs with Activity	28	28	34	24	17	19	41	25.0
Rigs with Reported Events	18	16	15	10	10	11	32	13.3
OPERATORS								
Active Operators	19	24	21	17	12	16	29	18.2
Reporting Operators	11	8	9	8	7	6	12	8.2
BOP DAYS								
Total BOP Days	5,178	6,808	7,108	3,962	3,822	4,322	31,200	5,200
Not-in-Operation BOP Days	1,636	1,709	1,883	1,225	933	1,259	8,645	1,441
In-Operation BOP Days	3,542	5,099	5,225	2,737	2,890	3,064	22,555	3,759
COMPONENT EVENTS								
Total Events Reported	110	69	87	21	46	43	376	62.7
Overall Event Rate	21.2	10.1	12.2	5.3	12.0	9.9	12.1	11.8
Not-in-Operation Events	62	33	45	7	19	15	181	30.2
Not-in-Operation Event Rate	37.9	19.3	23.9	5.7	20.4	11.9	20.9	19.9
Not-in-Operation Events per Well	0.4	0.2	0.2	0.1	0.2	0.1	0.3	0.2
In-Operation Events	48	36	42	14	27	28	195	32.5
In-Operation Event Rate	13.6	7.1	8.0	5.1	9.3	9.1	8.6	8.7
In-Operation Events per Well	0.3	0.2	0.2	0.1	0.2	0.2	0.3	0.2
BOP STACK MOVEMENTS								
Total Stack Starts	214	236	224	133	121	152	1,080	180.0
Successful Starts	182	237	210	121	121	144	1,015	169.2
Stack Pulls	11	10	36*	9*	16*	14*	96	16.0
LOC EVENTS								
Loss of Containment Events	0	0	0	0	0	0	0	NA

KEY: In-operation Not-in-operation

NOTES:

- Event rate is the number of events that occurred per 1,000 BOP days.
- The 2017–22 totals for rigs, operators, and wells with activity measures represent the number of unique entities.

* Includes some BOP stack pulls identified in WAR. Table 2 provides counts. These are not included in *Total Events Reported*.

SOURCE: U.S. DOT, BTS, SafeOCS Program.

APPENDIX D: COMPONENT FAILURES 2017-2022

Table 25: Components Involved in Reported Subsea System Failures

Component	2017 (n=1301)	2018 (n=1128)	2019 (n=908)	2020 (n=614)	2021 (n=365)	2022 (n=438)	Total (n=4754)
Regulator	8.8%	12.4%	13.1%	13.5%	13.2%	9.6%	11.5%
Solenoid Valve Hydraulic	9.5%	4.7%	12.4%	10.4%	3.8%	2.1%	7.9%
SPM Valve	9.9%	6.7%	6.1%	7.2%	5.2%	8.9%	7.6%
Slide Shear Seal Valve	6.7%	7.4%	3.1%	8.8%	7.4%	5.0%	6.3%
Shuttle Valve	5.4%	3.8%	6.2%	8.5%	7.1%	11.6%	6.3%
Piping Tubing	5.1%	7.1%	4.1%	3.7%	6.8%	2.7%	5.1%
Accumulator	3.3%	6.6%	2.5%	2.6%	2.2%	3.4%	3.8%
Bonnet Operating Seal	2.1%	2.5%	3.0%	3.3%	2.5%	2.3%	2.5%
Choke and Kill Valve	2.8%	1.6%	1.8%	1.0%	7.7%	0.9%	2.3%
Hardware_all other Mech. Elements	1.8%	2.7%	2.1%	0.8%	1.9%	1.8%	1.9%
Ram Block Seal	1.7%	1.8%	1.2%	2.1%	2.2%	3.9%	1.9%
Pressure Gauge	2.1%	1.8%	1.7%	1.1%	0.8%	4.1%	1.9%
Relief Valve	1.8%	1.5%	2.2%	1.5%	1.9%	1.1%	1.7%
Choke and Kill Valve Operator Seal	1.6%	1.0%	1.3%	4.7%	1.4%	0.7%	1.7%
Hardware	2.1%	2.7%	0.7%	1.3%	0.5%	0.9%	1.6%
Operating System Seal	1.8%	1.0%	1.0%	1.5%	0.8%	1.8%	1.3%
Gas Valve	0.5%	2.0%	2.8%	1.1%	0.5%	-	1.3%
Hose	0.8%	1.3%	2.3%	0.8%	0.5%	1.6%	1.3%
Pod Packer	0.1%	0.5%	4.4%	1.1%	1.4%	0.5%	1.3%
Pilot Operated Check Valve	0.8%	0.8%	1.8%	1.6%	0.5%	2.1%	1.2%
Interface Seal	0.9%	2.4%	0.7%	0.5%	0.3%	0.5%	1.1%
Choke and Kill Line	-	4.3%	-	-	-	-	1.0%
PBOF Cable	0.5%	0.8%	1.2%	1.5%	0.3%	2.3%	1.0%
Pod Hose	1.5%	0.2%	2.2%	0.3%	0.3%	0.5%	1.0%
Pressure Transducer	0.7%	0.5%	0.9%	1.1%	2.5%	1.6%	1.0%
SEA_Subsea Electronic Assembly	1.5%	0.6%	1.0%	0.3%	0.3%	0.2%	0.8%
Other	0.5%	0.1%	0.7%	1.1%	2.2%	2.3%	0.8%
Choke and Kill Connector_Receptacle_Female	0.5%	0.9%	0.7%	0.7%	1.6%	1.1%	0.8%
Hydraulic Stab	0.8%	0.6%	0.8%	1.1%	0.5%	0.9%	0.8%
Ball Valve	0.7%	0.2%	0.3%	1.1%	0.8%	2.3%	0.7%
Flowmeter	0.8%	1.2%	0.3%	0.3%	0.8%	0.2%	0.7%
Check Valve	0.8%	0.4%	0.7%	0.3%	1.6%	0.9%	0.7%
Packing Element	0.4%	0.6%	1.4%	0.2%	0.3%	1.1%	0.7%
Cylinder	0.1%	0.4%	0.3%	1.0%	3.0%	1.1%	0.7%

Pod Stab	1.7%	0.2%	0.3%	0.2%	0.3%	-	0.6%
Electrical Connector	0.7%	0.4%	0.7%	0.5%	0.8%	0.9%	0.6%
Locking Device	0.7%	1.3%	0.1%	-	0.3%	0.7%	0.6%
Gate Valve Hardware	1.4%	0.4%	0.1%	-	0.3%	0.5%	0.6%
SEM_Subsea Electronic Module	0.7%	0.1%	0.6%	0.8%	0.3%	1.1%	0.5%
Filter	0.3%	0.4%	0.4%	0.5%	1.1%	1.4%	0.5%
Metering Needle Valve	0.3%	0.7%	0.3%	1.1%	0.3%	-	0.5%
Trigger Valve	0.7%	0.1%	-	0.8%	1.4%	0.5%	0.5%
Hot Line Hose	0.8%	0.1%	0.3%	0.3%	1.4%	0.2%	0.5%
Choke and Kill Operator Hardware	0.3%	0.2%	0.7%	1.0%	0.5%	0.5%	0.5%
Depth Compensated Accumulator	1.0%	0.5%	-	0.2%	-	0.2%	0.4%
Secondary Gripper	0.8%	0.7%	-	-	-	0.5%	0.4%
Ram Block Hardware	0.5%	0.8%	0.2%	-	0.3%	0.5%	0.4%
Drillers Control Panel	0.6%	0.3%	0.4%	-	0.3%	0.9%	0.4%
Pod Receptacle	0.5%	0.5%	0.2%	-	0.3%	1.1%	0.4%
Compensated Chamber	0.4%	0.5%	0.1%	0.2%	0.5%	0.9%	0.4%
Central Control Console	0.3%	0.5%	0.3%	0.2%	0.5%	0.7%	0.4%
Solenoid Valve Electric	0.2%	0.7%	0.3%	0.3%	-	0.5%	0.4%
Pump	0.4%	0.5%	0.2%	0.3%	-	0.5%	0.4%
ROV Valve	0.2%	0.2%	0.6%	0.3%	0.8%	0.5%	0.4%
Flowline Seal	0.2%	0.4%	0.7%	0.5%	-	-	0.3%
Mud Boost Valve	0.2%	0.4%	0.4%	0.7%	0.3%	0.2%	0.3%
Bonnet Face Seal	0.4%	0.4%	0.2%	0.3%	0.5%	-	0.3%
Pressure Temperature Sensor	0.3%	0.4%	0.2%	0.2%	-	0.9%	0.3%
MUX Cable	0.3%	0.2%	0.1%	0.5%	0.8%	0.2%	0.3%
Ring Gasket	0.5%	0.2%	0.2%	0.2%	-	0.7%	0.3%
Packer	0.4%	0.4%	0.1%	-	0.3%	0.2%	0.3%
Selector Manipulator Valve	0.4%	0.2%	0.4%	-	0.3%	0.2%	0.3%
Flex Loop Hose	0.2%	0.3%	0.7%	-	0.5%	-	0.3%
End Connection	0.2%	0.2%	0.4%	0.3%	0.5%	-	0.3%
Timing Circuit	0.2%	0.2%	0.1%	1.0%	0.3%	-	0.3%
Choke and Kill Spool	0.2%	0.7%	0.1%	-	-	-	0.3%
HPU Control Panel	0.2%	-	0.7%	0.3%	0.3%	0.2%	0.3%
Bonnet Hardware_all other Mech. Elements	0.8%	-	-	-	-	0.5%	0.3%
Interconnect Cable	0.2%	0.4%	0.2%	-	0.5%	-	0.2%
Quick Dump Valve	0.1%	0.5%	0.1%	0.2%	0.3%	0.2%	0.2%
Hydraulic Tool	0.2%	0.4%	0.1%	-	0.3%	0.7%	0.2%
Instrumentation	0.5%	0.1%	0.3%	-	-	-	0.2%
MUX Cable Connector	-	0.3%	0.4%	0.2%	0.3%	-	0.2%
Inclinometer	0.2%	0.2%	0.3%	0.2%	-	-	0.2%

UPS	0.2%	-	0.4%	0.2%	-	-	0.2%
Studs and Nuts	-	0.5%	-	-	-	0.2%	0.1%
Auxiliary Control Panel	-	0.1%	0.1%	0.5%	0.3%	0.2%	0.1%
Wet Mate Connector	-	0.2%	0.2%	-	-	0.7%	0.1%
Primary Gripper	0.1%	0.1%	0.2%	-	-	0.7%	0.1%
Toolpushers Control Panel	0.1%	0.3%	0.1%	0.3%	-	-	0.1%
Software	0.2%	-	-	0.2%	0.5%	0.2%	0.1%
Ram Cavity	0.3%	0.1%	-	-	-	-	0.1%
Actuator	-	-	0.1%	-	0.5%	0.5%	0.1%
Conduit Manifold	0.4%	-	-	-	-	-	0.1%
Side Outlet	-	-	0.6%	-	-	-	0.1%
Hydraulic Gate Valve Actuator	0.2%	0.1%	0.1%	-	-	-	0.1%
Subsea Control Panel	0.1%	0.1%	0.1%	-	-	0.2%	0.1%
Pressure Switch	0.1%	-	0.2%	0.2%	-	-	0.1%
DRG Valve	0.2%	-	-	0.3%	-	-	0.1%
Choke and Kill Stab_Male	0.2%	-	0.1%	-	-	-	0.1%
Kill Hose	0.2%	-	0.1%	-	-	0.2%	0.1%
Variable Pilot Valve	0.1%	-	0.2%	-	-	-	0.1%
Slip Ring	-	0.1%	0.1%	0.2%	-	-	0.1%
Inside BOP	0.2%	-	-	0.2%	-	-	0.1%
Choke Hose	-	0.1%	0.1%	-	-	0.2%	0.1%
Reel	0.2%	-	-	0.2%	-	-	0.1%
Transducer	0.1%	0.1%	-	-	-	-	0.04%
Cable	-	0.1%	0.1%	-	-	-	0.04%
Riser Coupling	-	-	-	0.3%	-	-	0.04%
Vessel Piping	0.1%	-	-	-	0.3%	-	0.04%
Riser Control Box_RCB	0.1%	0.1%	-	-	-	-	0.04%
Junction Box	-	-	0.1%	-	0.3%	-	0.04%
Transponder	0.1%	0.1%	-	-	-	-	0.04%
Inner Barrel Lock	0.1%	-	-	-	-	0.2%	0.04%
Auto Choke Actuator	0.1%	0.1%	-	-	-	-	0.04%
Surface Control Unit	-	0.1%	0.1%	-	-	-	0.04%
HP Swivel	0.1%	-	-	-	0.3%	-	0.04%
Auto Choke Valve	0.2%	-	-	-	-	-	0.04%
Locking Dog	-	-	0.2%	-	-	-	0.04%
Kelly Valve	0.2%	-	-	-	-	-	0.04%
HFGS	0.1%	-	-	-	-	-	0.02%
Insert Packer	-	0.1%	-	-	-	-	0.02%
Manual Choke Actuator	-	-	-	-	0.3%	-	0.02%
Hydraulic Control Interface	-	-	-	-	-	0.2%	0.02%

Compensator	-	-	-	-	-	0.2%	0.02%
ROV Stinger Hot Stab	0.1%	-	-	-	-	-	0.02%
Choke Manifold Control Valve	0.1%	-	-	-	-	-	0.02%
Other Line	0.1%	-	-	-	-	-	0.02%
Manual Tool	-	-	-	0.2%	-	-	0.02%
Conduit Line	-	0.1%	-	-	-	-	0.02%
Block	0.1%	-	-	-	-	-	0.02%
Battery	-	0.1%	-	-	-	-	0.02%
Drillstring Safety Valve	0.1%	-	-	-	-	-	0.02%
BLAT	0.1%	-	-	-	-	-	0.02%

NOTE: Percent refers to percent of reported failures. Dash indicates zero.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Table 26: Components Involved in Reported Surface System Failures

Component	2017 (n=110)	2018 (n=69)	2019 (n=87)	2020 (n=21)	2021 (n=46)	2022 (n=43)	Total (n=376)
Packing Element	8.2%	18.8%	11.5%	9.5%	8.7%	11.6%	11.4%
Ram Block Seal	9.1%	8.7%	6.9%	-	17.4%	9.3%	9.0%
Accumulator	9.1%	10.1%	14.9%	4.8%	2.2%	4.7%	9.0%
Gate Valve Hardware	11.8%	5.8%	1.1%	-	2.2%	27.9%	8.2%
Choke and Kill Valve	10.0%	5.8%	4.6%	-	6.5%	7.0%	6.6%
Hardware	11.8%	5.8%	1.1%	-	6.5%	4.7%	6.1%
Regulator	1.8%	2.9%	8.0%	19.0%	10.9%	2.3%	5.6%
Bonnet Face Seal	3.6%	2.9%	8.0%	-	4.3%	7.0%	4.8%
Operating System Seal	1.8%	2.9%	6.9%	4.8%	10.9%	2.3%	4.5%
Inside BOP	0.9%	1.4%	5.7%	-	10.9%	-	3.2%
Pump	3.6%	-	3.4%	4.8%	2.2%	7.0%	3.2%
Bonnet Operating Seal	1.8%	2.9%	2.3%	4.8%	6.5%	2.3%	2.9%
Selector Manipulator Valve	1.8%	2.9%	4.6%	9.5%	2.2%	-	2.9%
Relief Valve	4.5%	1.4%	1.1%	9.5%	-	-	2.4%
Hardware_all other Mechanical Elements	3.6%	2.9%	1.1%	-	-	-	1.9%
Piping Tubing	-	-	-	9.5%	-	7.0%	1.3%
Instrumentation	0.9%	2.9%	2.3%	-	-	-	1.3%
Bonnet Hardware_all other Mech. Elements	-	1.4%	2.3%	4.8%	-	-	1.1%
Hose	1.8%	1.4%	1.1%	-	-	-	1.1%
Auto Choke Valve	2.7%	-	-	-	-	-	0.8%
Other	-	-	1.1%	-	2.2%	2.3%	0.8%
Drillstring Safety Valve	1.8%	-	-	-	2.2%	-	0.8%

Choke and Kill Valve Operator Seal	1.8%	-	1.1%	-	-	-	0.8%
Hydraulic Stab	-	4.3%	-	-	-	-	0.8%
SPM Valve	-	4.3%	-	-	-	-	0.8%
Ram Cavity	0.9%	1.4%	-	-	-	-	0.5%
Pressure Switch	-	-	1.1%	4.8%	-	-	0.5%
Locking Device	-	1.4%	-	-	-	2.3%	0.5%
Hydraulic Gate Valve Actuator	-	-	1.1%	4.8%	-	-	0.5%
Ball Valve	0.9%	1.4%	-	-	-	-	0.5%
Auto Choke Actuator	0.9%	-	-	-	2.2%	-	0.5%
Shuttle Valve	-	1.4%	1.1%	-	-	-	0.5%
Packer	-	-	2.3%	-	-	-	0.5%
Ram Block Hardware	-	-	-	-	-	2.3%	0.3%
Choke Hose	-	-	-	4.8%	-	-	0.3%
Gooseneck	-	-	1.1%	-	-	-	0.3%
Gas Valve	-	1.4%	-	-	-	-	0.3%
Choke and Kill Spool	0.9%	-	-	-	-	-	0.3%
Choke and Kill Line	0.9%	-	-	-	-	-	0.3%
HPU Control Panel	-	1.4%	-	-	-	-	0.3%
Flange	0.9%	-	-	-	-	-	0.3%
Flex Loop Hose	-	-	-	-	2.2%	-	0.3%
DRG Valve	0.9%	-	-	-	-	-	0.3%
Central Control Console	-	-	1.1%	-	-	-	0.3%
Pressure Transducer	-	1.4%	-	-	-	-	0.3%
End Connection	-	-	1.1%	-	-	-	0.3%
UPS	-	-	-	4.8%	-	-	0.3%
Drillers Control Panel	-	-	1.1%	-	-	-	0.3%
Kick out Sub	0.9%	-	-	-	-	-	0.3%

NOTE: Percent refers to percent of reported failures. Dash indicates zero.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

APPENDIX E: GLOSSARY

Abandonment: Abandonment is a temporary or permanent subsurface isolation to prevent undesired communication between distinct zones and fluid movement out of a well using validated well barriers.

Active Operators: Operators who conducted well operations (drilling or non-drilling) in the GOM OCS during the listed period.

Annular Preventer: A toroidal shaped device that can seal around any object in the wellbore or upon itself.

Blind Shear Ram: A closing and sealing component in a ram blowout preventer designed to shear certain tubulars in the wellbore, or close on an empty wellbore, and then seal off the bore.

Blowout: An uncontrolled flow of well fluids and/or formation fluids from the wellbore to surface or into lower pressured subsurface zones, per API Standard 53. A well can experience a blowout when the formation's pressure is higher than the fluid's hydrostatic pressure.

Blowout Preventer (BOP): A ram or annular device designed to contain wellbore pressure in the well.

BOP Control Fluid: A term commonly used for both the biodegradable water-based fluid or the hydraulic oil used to pilot or power the WCE on BOP stacks.

BOP Control Pod: An assembly of subsea valves and regulators hydraulically or electrically operated which will direct hydraulic fluid through special porting to operate BOP equipment.

BOP Control System: The collection of pumps, valves, accumulators, fluid storage and mixing equipment, manifold, piping, hoses, control panels, and other API Specification 16D items necessary to operate the BOP equipment.

BOP Days: The number of days during which some or all the WCE components may have been in use and had any likelihood of a failure.

BOP Stack: An assembly of annular and ram type preventers, together with choke and kill valves, installed on top of the wellhead during well construction activities.

Casing Shear Ram: A closing component in a ram blowout preventer that is capable of shearing or cutting certain tubulars in the wellbore.

Choke and Kill Lines: High pressure pipes connecting the side outlet valves on the BOP stack to the choke manifold to allow controlled flow in and out of a closed BOP stack.

Consumables: For purposes of this report, consumables may include seals and other components that have an indeterminable expected life because of variables in the operating conditions.

Decommissioning: See Abandonment.

Drilling: The perforation of the earth's surface by mechanical means. It includes all operations for preventing the collapse of the sides of the hole, or for preventing the hole from being filled with extraneous materials including water.

Drilling Fluid: The fluid added to the wellbore to facilitate the drilling process and control the well.

Drilling Rig: A mobile structure housing the integrated system for drilling wells. Offshore drilling rigs are either floating (e.g., a drillship or semi-submersible) or bottom supported (e.g., a jack-up or rig unit on a production platform). Floating rigs typically use subsea WCE systems, and bottom supported rigs tend to use surface WCE systems.

Event Rate: The event rate reflects the number of reported events per 1,000 BOP days. The not-in-operation event rate considers only in-operation BOP days, and the in-operation event rate considers only in-operation BOP days. The event rate is calculated as: events / BOP days × 1,000.

In-Operation (Subsea System): A subsea BOP stack is in operation after it has completed a successful initial subsea pressure test per API Standard 53.

In-Operation (Surface System): A surface BOP stack is in operation after it has completed a successful pressure test of the wellhead connection to the wellbore per API Standard 53.

Integrated Riser Joint: A Managed Pressure Drilling (MPD) riser joint that has an annular preventer, choke and kill valves and a bearing assembly incorporated.

Intervention: A workover operation in which a well is re-entered for a purpose other than to continue drilling or to maintain or repair it.

Loss of Containment: An external leak of wellbore fluids outside of the pressure containing equipment boundary.

Managed Pressure Drilling: A method of drilling where the well bore circulation system is contained in a closed-loop allowing pore-pressure, formation fracture pressure, and bottom hole pressure to be balanced and managed at surface.

Mechanical Barrier: Subset of physical barriers that feature engineered, manufactured equipment. Does not include set cement or a hydrostatic fluid column. Examples include permanent or retrievable bridge plugs, downhole packers, wellhead hanger seals, and liner hanger seals.

Multiplex Control System (MUX): A microprocessor-based BOP control system used predominantly in deep water that sends multiple coded signals to and from the control pods through a single cable to overcome the time requirements of the hydraulic control systems used in shallow water.

Non-Drilling Operations: Well operations including, for example, intervention, workover, temporary abandonment, and permanent abandonment.

Not-In-Operation (Subsea System): The BOP stack is not in operation when it is being maintained, inspected, and tested in preparation for use. The BOP stack changes from in operation to not in operation when either the BOP is removed from the wellhead or the LMRP is removed from the lower BOP stack. When the BOP stack is on deck or is being run, pulled, or retrieved, it is considered not in operation.

Not-In-Operation (Surface System): The BOP stack is not in operation when it is being maintained, inspected, and tested in preparation for use. A surface BOP stack changes from in operation to not in operation when the external barrier is intentionally disabled for repair/replacement, or at the end of the well.

Pipe Ram Preventer: A device that can seal around the outside diameter of a pipe or tubular in the wellbore. These can be sized for a range of pipe sizes (variable pipe ram) or a specific pipe size.

Pre-Spud Operations: The period preceding the start of drilling activities.

Remotely Operated Vehicle (ROV): An unmanned underwater robot connected to the rig by a control cable which transmits commands to the robot and video signals to the rig. The ROV is used to observe the underwater equipment and to carry out some rudimentary operations when commanded by the pilot.

Rig: See Drilling Rig.

Rigs with Activity: This includes all rigs which had both a contract and permit to perform drilling and non-drilling activities on the OCS during the referenced period.

Root Cause: The cause (condition or action) that begins a cause/effect chain and ends in the equipment component failure. If eliminated, it would prevent the reoccurrence of the event (under investigation) and similar occurrences.

Shear Ram: See Blind Shear Ram or Casing Shear Ram.

Stack Pull (Subsea System): When either the BOP is removed from the wellhead or the LMRP is removed from the lower BOP stack and recovered to the rig to repair a failed component. An event cannot be classified as a BOP stack pull until after the BOP stack is in operation (see Stack Retrieval).

Stack Pull (Surface System): When a BOP component fails during operations and requires well conditioning and a mechanical barrier placement to make necessary repairs.

Stack Retrieval: The recovery of the LMRP or the BOP stack before it is in operation. If the LMRP or BOP stack is recovered to the rig any time after deployment has begun and before initial latch-up tests are passed, it is considered a BOP stack retrieval. Additionally, retrieval of the LMRP for a weather-related event or evacuation is not considered a stack pull.

Stack Run: The activity of deploying a subsea BOP stack from the rig to the subsea wellhead.

Stack Start: In this report, BOP stack start means when a surface BOP stack is assembled on the wellhead.

Subunit: See Well Control Equipment Subunits.

Well Construction: A set of operations, including drilling, that create the hole and provide the barriers to fluid migration in the form of surface, intermediate and production casings, tubing, and packers installed in the well above the completion interval. This work is directed by the lease operator employing the drilling contractor and third-party services equipment and personnel.

Well Control Equipment: Systems and subsystems that are used to control pressure within the wellbore, per API Standard 53.

Well Control Equipment Subunit: Well control equipment components are categorized according to the following subunits: auxiliary equipment, BOP control systems (primary, secondary, and emergency), BOP stack system, choke manifold system, diverter system, and riser system.

Wellbore Fluid: The oil or gas diluted fluids, commonly referred to as hydrocarbons, from a reservoir that would typically be found in an oil or gas well.

Wells Spudded: The number of wells that were started, or "spudded," during the listed period. Wells spudded are a subset of total wells with activity.

Wells with Activity: The number of wells worked on by rigs, regardless of the well operation, during the referenced period.

Workover: An operation on a completed well intended to maintain or increase production but is not routine maintenance.

Detection Method Terms

Casual Observation: An unplanned or non-routine observation. This could be a simple walk by the component.

Continuous Condition Monitoring: Monitoring involving the use of intelligent instrumentation with alarms and recording devices.

Corrective Maintenance: Unscheduled maintenance or repairs.

Function Test: The operation of equipment to confirm that it does what it is expected to do.

Inspection: Company-conducted inspection, which may consist of visual or other examination.

On-demand: Inability to function when required.

Periodic Condition Monitoring: Regular checks.

Periodic Maintenance: Planned, scheduled maintenance routine.

Pressure Test: The application of pressure to a piece of equipment or a system to verify its pressure containment capability.

Appendix F: Acronyms

ANSI: American National Standards Institute

API: American Petroleum Institute

BOP: Blowout preventer

BSEE: Bureau of Safety and Environmental Enforcement

BSR: Blind shear ram

BTS: Bureau of Transportation Statistics

CFR: Code of Federal Regulations

C/K: Choke or kill

CIPSEA: Confidential Information Protection and Statistical Efficiency Act

D&I: Disassembly and inspection

DOI: Department of the Interior

DOT: Department of Transportation

EHBS: Emergency hydraulic backup system

GOM: Gulf of Mexico

HPU: Hydraulic power unit

IADC: International Association of Drilling Contractors

IOGP: International Association of Oil and Gas Producers

I&A: Investigation and failure analysis

IRJ: Integrated riser joint

JIP: Joint industry project

LMRP: Lower marine riser package

LOC: Loss of containment

MASP: Maximum anticipated surface pressure

MGS: Mud-gas separator

MIT: Maintenance, inspection, and testing

MPD: Managed pressure drilling

MUX: Multiplex control system

OCS: Outer Continental Shelf

OEM: Original equipment manufacturer

PBOF: Pressure balanced, oil-filled

QA/QC: Quality assurance/quality control

RCFA: Root cause failure analysis

ROV: Remotely operated vehicle

SD: Standard deviation

SME: Subject matter expert

SPM: Sub-plate mounted

WAR: Well activity report (per 30 CFR 250.743)

WCE: Well control equipment

WCR: Well Control Rule