Well Control Equipment Systems Safety

2019 Annual Report

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

WELL CONTROL EQUIPMENT SYSTEMS SAFETY

2019 Annual Report

Acknowledgements

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Recommended Citation:

Bureau of Transportation Statistics. *Well Control Equipment Systems Safety – 2019 Annual Report. Washington, D.C.: United States Department of Transportation, 2019.*

https://doi.org/10.21949/1518379

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Executive Summary

The *Well Control Equipment Systems Safety – 2019 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) during the calendar year. This report is based on information collected through SafeOCS, a confidential reporting program for the collection and analysis of data to advance safety in offshore energy operations. It includes an analysis of reported events involving WCE systems, including blowout preventer (BOP) equipment, and other key information about the events such as root causes and follow-up actions. Data is presented by WCE system type (subsea or surface) and by when the event occurred (in-operation or not-in-operation).

The report is based on data from 907 subsea WCE system notifications and 87 surface WCE system notifications submitted to SafeOCS in 2019, the third full year of WCE failure reporting, representing a decrease of 16.9 percent in reported WCE events from 2018 to 2019. This dataset does not include every WCE failure event that occurred in the GOM OCS in 2019, as some events were not reported to SafeOCS. An evaluation indicates that this apparent underreporting tended to be higher for surface WCE system events.

Overall, well activity decreased from 2018 to 2019 as measured by the number of days during which WCE components were in use (BOP days). When adjusted for the amount of well activity, reported event rates decreased 15.4 percent from 2018 to 2019 and showed an overall decrease since 2017, driven by a decrease in the event rate for subsea WCE systems. Of the 994 reported events, 842 (84.7 percent) occurred while not in operation, similar to prior years. No leaks of wellbore fluids to the environment, classified as losses of containment, were reported to SafeOCS in 2019, and only one such event has been reported since 2017.

Subsea WCE System Events

For subsea WCE systems, 799 not-in-operation events and 108 in-operation events were reported. When adjusted for well activity, reported event rates decreased from 2018 to 2019 by 13.3 percent for in-operation events and 23.1 percent for not-in-operation events. Ten of 19 operators with subsea well operations in the GOM reported equipment failure events for 21 of 28 subsea system rigs with activity. The BOP control systems, which have the most redundancies, had the highest proportion of events compared to other WCE subunits. Most events were classified as leaks, none of which were leaks of wellbore fluids. The most commonly reported root causes were wear and tear (reported for 44.6 percent of not-in-operation events and 49.1 percent of in-operation events), design issue (19.6 and 20.4 percent), procedural error (13.9 and 8.3 percent) and maintenance error (13.0 and 6.5 percent). Eight events, all involving leaks of control fluid, resulted in a stack pull.

Two BOP control fluid issues were observed among the reported subsea WCE system events. The first issue pertains to nickel leaching from the use of demineralized water in control fluid systems. The second issue pertains to what was described as calcium soap buildup in some control fluid systems, potentially caused by mixing the fluid concentrate with a chemical commonly used to disinfect drinking water on a rig. These issues can be mitigated by ensuring the water supplied to the BOP fluid mix system meets the specifications required by both the WCE manufacturer and the BOP fluid concentrate manufacturer.

Surface WCE System Events

For surface WCE systems, 43 not-in-operation events and 44 in-operation events were reported. When adjusted for well activity, reported event rates increased from 2018 to 2019 by 24.6 percent for in-operation events and 30.7 percent for not-in-operation events; however, their usefulness in evaluating potential trends is limited by the low count of reported events. Nine of 22 operators with surface well operations in the GOM reported equipment failure events for 15 of 35 surface system rigs with activity. Most events were attributed to the BOP control and BOP stack systems, and most events were classified as leaks, none of which were leaks of wellbore fluids. The most commonly reported root cause was wear and tear, reported for 46.5 percent of not-in-operation events and 50.0 percent of in-operation events. Twenty reported events resulted in a stack pull, and 16 additional surface stack pull events were identified in BSEE Well Activity Report (WAR) data. Most surface stack pulls in 2019 were due to some level of internal leak across the annular packing element.

Next Steps

SafeOCS continues to focus on improving data quality and accessibility, including identifying potential improvements to the data collection instrument and ways to share learnings with stakeholders.

INTRODUCTION

The *2019 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 during the calendar year. These failures occurred during rig 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. The annual report includes the following:

- Overview of the types of failures reported
- Analysis of root causes
- Summary of reported lessons learned from failure event investigations

It also discusses opportunities to improve data quality and accessibility. This report differs from previous years in that it further emphasizes the separation between in-operation events and not-in-operation events to highlight their different risk levels. The title was also changed from *Blowout Prevention System Safety* to more accurately reflect the scope of the data collection, which includes blowout preventer (BOP) systems, as well as other well control equipment systems.

About SafeOCS

The Department of Transportation's Bureau of Transportation Statistics (BTS), a principal federal statistical agency, entered an interagency agreement with the Department of the Interior's Bureau of Safety and Environmental Enforcement (BSEE) to develop, implement, and operate the SafeOCS program. SafeOCS is a confidential reporting program that collects and analyzes data to advance safety in oil and gas operations on the OCS. The objective of SafeOCS is to capture and share essential information across the industry about accident precursors and potential hazards associated with offshore operations. The Confidential Information Protection and Statistical Efficiency Act (CIPSEA) protects the confidentiality of all data submitted directly to SafeOCS.[1]

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

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 (JIP) on BOP Reliability Data**: 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).
- **Internal Review Team**: SafeOCS retained subject matter 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.

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[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] Previous annual reports were titled *Blowout Prevention System Safety Events*.

- **BSEE**: BSEE provided BTS with well-related data used for data validation, benchmarking, and development of exposure measures, described under *On Estimating Exposure Measures for Equipment and Activity Levels* (page 5).

Context for WCE Events

WCE systems control the flow of formation or other fluids during offshore oil and gas well operations.[3] This report focuses on events that occurred while maintaining, inspecting, testing, and operating equipment prior to and during rig-based well operations requiring the use of well control equipment systems.

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. In addition to drilling the hole to the correct size and depth, well construction includes preventing the hole from collapsing and maintaining pressure integrity within the hole. This process involves running lengths of various size pipe in the wellbore and cementing them in place to isolate any potential flow zone[4] and prepare the well for subsequent production operations.

WCE systems are critical to ensure 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:

- Auxiliary equipment
- BOP controls
- BOP stack
- Diverter
- Choke and kill
- Riser

Of these, the BOP controls and the BOP stack systems, which are assembled from thousands of components, consume the most hours of maintenance of any equipment on the rig and are

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

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

the most important for safeguarding against adverse events. Normally, the BOP controls and BOP stack systems are on standby. Operators are required to conduct and meet API Standard 53 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. This cycle of maintenance, inspection, and testing is discussed in more detail under *Operational States of Subsea WCE Systems* (page 13) and *Operational States of Surface WCE Systems* (page 36).

This report presents data sorted by WCE system type—subsea or surface—and then by in-operation or not-in-operation events. In-operation events are further evaluated as to whether a more serious event followed, such as a BOP stack pull or, worse, a loss of containment (LOC). The following factors were considered in determining how to present the data:

- **BOP System Complexity**: Subsea systems have a much higher population of components than surface BOP systems, most of which are related to redundancies in the BOP control systems. See further discussion in Chapter 2 and Appendix E.
- **Accessibility of Equipment**: Most subsea system equipment is underwater and limited to observation and simple intervention by a remotely operated vehicle (ROV)[5]; whereas, surface system equipment is visible and accessible by the rig crew at all times.[6]
- **Environmental Impact**: The potential consequences of a hydraulic leak (representing the majority of component failures) from a surface BOP control system, which predominantly uses petroleum-based hydraulic oil, are more significant than from a subsea BOP control system, which uses water-based fluids.[7]

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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] Wellbore fluid from either system that results in a spill or loss of containment (LOC) would have similar potential environmental consequences.

- **Management of Equipment**: Rigs with subsea BOPs have a full-time crew of specialized subsea engineers that operate and maintain the well control equipment. Surface BOP systems are operated by the drill crew and maintained by the rig mechanic, in addition to their standard duties. These crew differences lead to different operational practices for subsea systems as compared to surface systems. For example, for surface systems, most WCE is sent to shore for major maintenance and investigation activities, whereas most of these activities are conducted onsite for subsea systems.
- **Risk:** Events that occur when the system is not in operation present a very different set of potential consequences than events that occur when the system is in operation. Events discovered and corrected when the system is not in operation present less risk to the environment than in-operation events. Importantly, not all in-operation events result in consequences because of equipment redundancy and the relatively short period that well pressures can lead to a blowout.[8] Understanding what components fail while in operation, why they fail, and how and when they fail is critical to reduce or eliminate similar events in the future.

On Estimating Exposure Measures for Equipment and Activity Levels

Exposure measures are sometimes referred to as denominator data or normalizing data because they represent the population on which statistical values are based. SafeOCS uses exposure measures to estimate the population of equipment subject to failure and its characteristics. These measures aid in evaluating aggregated equipment failure information and are used in SafeOCS publications, including this annual report.

SafeOCS developed exposure measures from BSEE data sources, including well activity reports (WARs), which oil and gas operators must submit weekly for active well operations in the Gulf of Mexico OCS Region, per 30 CFR 250.743. Rig WAR data is used to develop several measures (numbered one through seven below) that approximate the number of active

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

operators and the amount of rig activity.[9] An additional measure, wells spudded (number eight below), is developed from the BSEE boreholes table and provides information on the extent of new activity in 2019. 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.
3. **Rigs with activity**: The number of rigs with operations.
4. **BOP days**: The number of days during which some or all of the WCE components may have been in use 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. For rigs with two BOP stacks, the number of days the rig was operating is multiplied by 1.48, based on the determination that a rig with two subsea BOP stacks has approximately 1.48 times the number of WCE components as a rig with one BOP stack.[10] 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 stack was moved from one location to another (hopped) while staying submerged.
6. **BOP stack starts**: The number of times a surface BOP stack was assembled on the surface wellhead.
7. **BOP latches and unlatches**: The number of times a subsea BOP stack was latched or unlatched from a wellhead.
8. **Wells spudded**: The number of new wells spudded.

[9] Non-rig WARs are excluded. Rig WARs are included for all well operation types.

[10] The component count of a subsea rig with two BOP stacks divided by the component count of a subsea rig with one BOP stack = 1.48. See Appendix E for more detail.

Analysis Information and Data Adjustments

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

- 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 reported results and references to previous data in this report represent updated numbers unless otherwise stated.

CHAPTER 1: NUMBERS AT A GLANCE

Table 1: Numbers at a Glance, 2017-19

MEASURE	2017	2018	2019
ACTIVITY			
Wells with Activity	325	389	385
Wells Spudded	152	193	188
RIGS			
Rigs with Activity	60	59	63
Rigs with Reported Events	47	40	36
OPERATORS			
Active Operators	27	32	29
Reporting Operators	18	14	13
BOP DAYS			
Total BOP Days	15,892	16,906	16,628
In-Operation BOP Days	9,965	10,720	10,294
Not-in-Operation BOP Days	5,927	6,186	6,335
COMPONENT EVENTS			
Total Events Reported*	1,421	1,196	994
In-Operation Events	245	172	152
In-Operation Event Rate	24.6	16.0	14.8
In-Operation Events per Well	0.8	0.4	0.4
Not-in-Operation Events	1,176	1,024	842
Not-in-Operation Event Rate	198.4	165.5	132.9
Not-in-Operation Events per Well	3.6	2.6	2.2
LOC EVENTS			
Loss of Containment Events	1	0	0

KEY: In-operation Not-in-operation
NOTE: *Total Events Reported excludes any events identified in WAR data.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

For 2019, SafeOCS received event notifications from one region, the GOM OCS, which accounts for over 99 percent of annual oil and gas production on the OCS.[11] Table 1 lists measures related to all GOM OCS wells undergoing activity, together with event data, during each of the last three years. As shown in the table, 994 events were reported in 2019, most of which (84.7 percent) occurred while not in operation. None of the reported events resulted in a loss of containment.

Regarding the extent of well activity on the GOM OCS, Table 1 shows that from 2018 to 2019, the number of wells with activity and total BOP days remained about the same with a similarly sized fleet (BOP days are shown in Figure 2). There were 29 operators actively involved in well activities, and of these, 13 submitted event notifications.

[11] Outer Continental Shelf Oil and Gas Production, BSEE, accessed Mar. 17, 2021, https://www.data.bsee.gov/Production/OCSProduction/Default.aspx.

When adjusted for the amount of well activity, approximately 59.8 events occurred per 1,000 BOP days, representing a 15.4 percent decrease from 2018 to 2019.[12] The event rates in Table 1 show that approximately 14.8 in-operation events occurred per 1,000 in-operation BOP days, and approximately 132.9 not-in-operation events occurred per 1,000 not-in-operation BOP days. The in-operation event rate decreased from 2018 by 7.5 percent and showed an overall decrease of 39.8 percent since 2017. Similarly, the not-in-operation event rate decreased from 2018 by 19.7 percent and showed an overall decrease of 33.0 percent since 2017.

On a per well basis, Table 1 shows that approximately 0.4 in-operation and 2.2 not-in-operation events were reported per well with activity. In-operation events per well remained about the same compared to 2018, and the measure shows an overall decrease of 50.0 percent (0.8 to 0.4) since 2017. Similarly, not-in-operation events per well show an overall decrease of 38.9 percent since 2017 (3.6 to 2.2).

Figure 1 (page 10) shows the number of WCE failure events reported to SafeOCS and identified in WARs. BOP days are shown in Figure 2. WAR data was evaluated to cross-reference the timing and occurrence of failures reported to SafeOCS and identify failures that may not have been reported to SafeOCS, resulting in a better approximation of the complete set of records for failure events that occurred in the GOM OCS in 2019. In total, 1,331 distinct well control equipment failure events were identified, 994 of which were reported to SafeOCS and the remainder were identified in WAR data.[13] This evaluation indicates that overall, 25.3 percent of known failure events in 2019 were not reported to SafeOCS; therefore, reporting of WCE failures to SafeOCS appears to be incomplete. This apparent underreporting tended to be higher for surface system events, of which 67.7 percent of distinct not-in-operation events and 63.0 percent of distinct in-operation events were not reported to SafeOCS.

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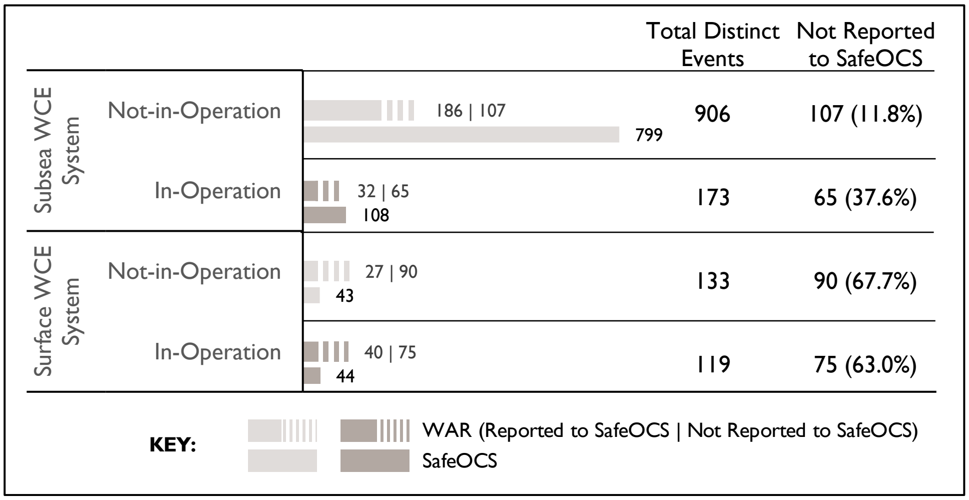
[12] 59.8 events per 1,000 BOP days in 2019 versus 70.7 events per 1,000 BOP days in 2018.

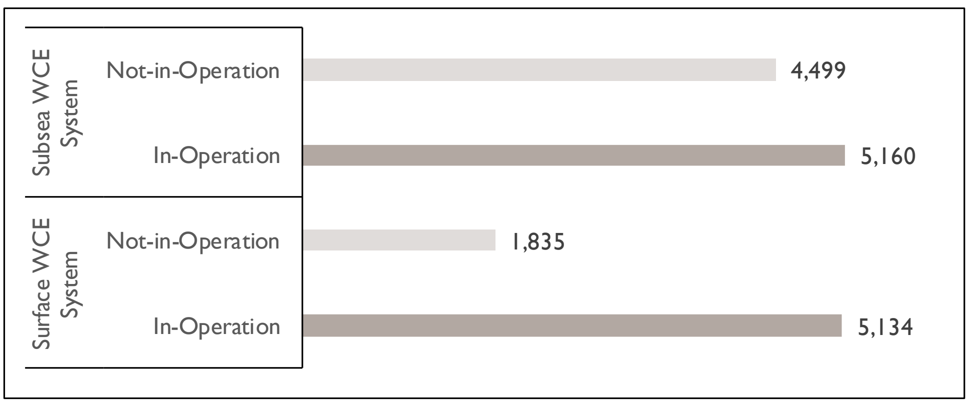
[13] Six hundred twenty-two (622) well control equipment failure events were identified in WAR data. Of these, 285 were reported to SafeOCS and 337 were not. A failure event identified in WAR data was determined to be also reported to SafeOCS if it occurred on the same rig, the WCE system was in the same state (in-operation or not-in-operation), and it occurred within seven days of the date reported to SafeOCS.

Figure 1: Sources of WCE Event Reporting, 2019



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

Figure 2: BOP Days, 2019



KEY: In-operation Not-in-operation
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Chapter 2: Subsea WCE System Events

Table 2: Subsea Systems Numbers at a Glance, 2017-19

MEASURE	2017	2018	2019
ACTIVITY			
Wells with Activity	165	172	182
Wells Spudded	87	107	102
RIGS			
Total Rigs with Activity	32	31	28
With One Subsea Stack	10	9	13
With Two Subsea Stacks	22	22	15
Rigs with Reported Events	29	24	21
OPERATORS			
Active Operators	17	16	19
Reporting Operators	11	10	10
BOP DAYS			
Total BOP Days	10,720	9,963	9,659
In-Operation BOP Days	6,324	5,677	5,160
Not-in-Operation BOP Days	4,396	4,286	4,499
COMPONENT EVENTS			
Total Events Reported*	1,307	1,127	907
In-Operation Events	188	137	108
In-Operation Event Rate	29.7	24.1	20.9
In-Operation Events per Well	1.1	0.8	0.6
Not-in-Operation Events	1,119	990	799
Not-in-Operation Event Rate	254.5	231.0	177.6
Not-in-Operation Events per Well	6.8	5.8	4.4
BOP STACK MOVEMENTS			
Total Stack Runs	200	178	204
Successful Runs	167	152	151
Stack Pulls	10	8	8
LOC EVENTS			
Loss of Containment Events	1	0	0

KEY: In-operation Not-in-operation
NOTE: *Total Events Reported excludes any events identified in WAR data.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Table 2 lists measures related to all GOM OCS *subsea* wells undergoing activity, together with event data, during each of the last three years. Overall, 907 events were reported for subsea BOP systems in 2019, equating to 91.2 percent of all events. Each year since 2017, more than 90.0 percent of reported events occurred on subsea BOP systems as opposed to surface systems.[14] As in previous years, most 2019 events (88.1 percent) occurred while not in operation. Approximately 7.4 not-in-operation events were reported for each in-operation event.

Of the 108 in-operation events, eight (7.4 percent) resulted in a stack pull. About 5.3 percent (8 of 151) of successful subsea BOP stack runs—meaning the equipment passed all initial latch-

[14] 1,307 / 1,421 (92.0 percent) in 2017; 1,127 / 1,196 (94.2 percent) in 2018, and 907 / 994 (91.2 percent) in 2019. The total number of reported events per year can be found in Table 1.

up testing and went into operation—eventually led to a stack pull in 2019, similar to 2018.

Regarding subsea well activity, Table 2 shows that from 2018 to 2019, the number of subsea wells with activity increased by 10 and total subsea BOP days decreased modestly by 3.1 percent with a fleet three rigs smaller. On average, each subsea system rig conducted well operations on 6.5 GOM OCS wells in 2019, compared to 5.5 in 2018.[15] There were 204 total subsea BOP stack runs[16] and 151 successful stack runs for 182 wells with operations in 2019.

The subsea system event rates in Table 2 show that approximately 20.9 in-operation events occurred per 1,000 in-operation BOP days, and approximately 177.6 not-in-operation events occurred per 1,000 not-in-operation BOP days. The subsea system in-operation event rate decreased from 2018 by 13.3 percent and showed an overall decrease of 29.6 percent since 2017. Similarly, the subsea system not-in-operation event rate decreased from 2018 by 23.1 percent and showed an overall decrease of 30.2 percent since 2017.

On a per well basis, Table 2 shows that approximately 0.6 in-operation and 4.4 not-in-operation events were reported per subsea well with activity. In-operation events per subsea well decreased from 2018 by 25.0 percent (0.8 to 0.6) and showed an overall decrease of 45.5 percent (1.1 to 0.6) from 2017 to 2019. Not-in-operation events per subsea well decreased from 2018 by 24.1 percent (5.8 to 4.4) and showed an overall decrease of 35.3 percent from 2017 to 2019 (6.8 to 4.4).

Reporting Operators

Figure 3 shows subsea system events and rig activity (measured in BOP days) for the 19 active operators in 2019. The rig activity for any one operator may come from multiple rigs. In 2019, 10 of the 19 active subsea system operators (21 of the 28 active rigs) submitted event notifications. This does not represent an increase in events over 2018 for the operators when

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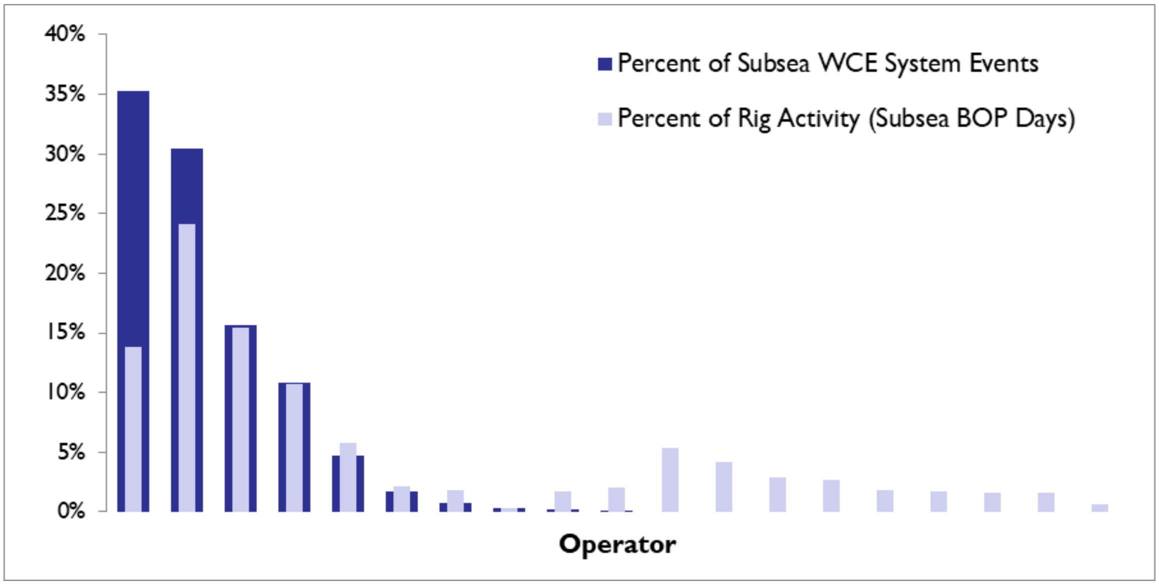
[15] 182 / 28 in 2019; 172 / 31 in 2018.

[16] Including stack hops (when the stack is moved from one location to another while staying submerged).

10 of 16 submitted notifications. While not all operators reported events, 75.0 percent of active subsea rigs were represented in event reporting, similar to 2018.

Figure 3: Subsea System Events and Rig Activity by Operator, 2019



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

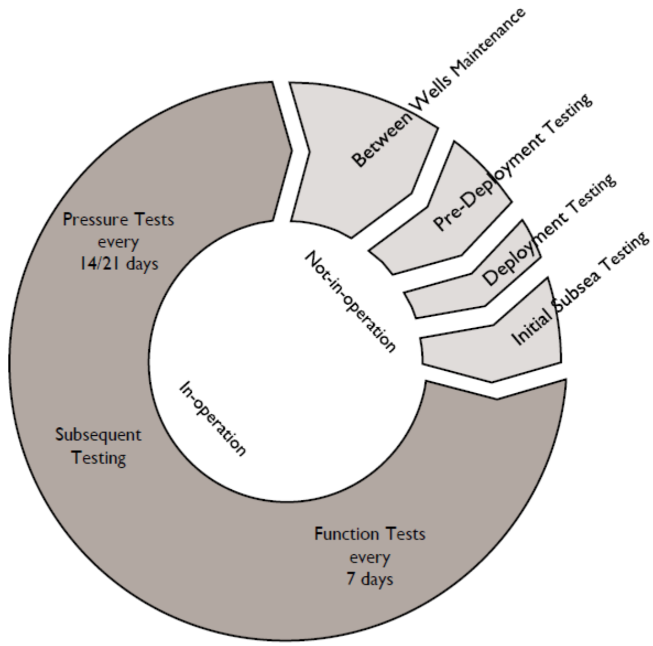
Operational States of Subsea WCE Systems

The remainder of this chapter separates events into two states, where applicable, based on when the event occurred: *in-operation* and *not-in-operation*. This section provides an overview of these states and the various phases within them to provide additional context for reported events. Figure 4 provides a visual representation.

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.

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 at least equal to formation pressure at all times. 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 when the BOP stack is not in operation. BSEE regulations codify MIT requirements, including those of API Standard 53.[17] The following provides more detail about each phase of MIT.

Figure 4: The Cycle of Maintenance, Inspection, and Testing



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

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.

- **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.

[17] 30 CFR 250.737, 250.739.

- **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 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.

- **Deployment Testing:** Pressure tests of the choke and kill lines, which provide fluid pressure control and allow drilling or wellbore fluids to be evacuated from the well safely if needed, are carried out during stack deployment. The choke and kill lines form a circuit between the BOP stack and the choke manifold and can only be tested when they are all properly connected. Additional detail is provided in Appendix F in the discussion of the riser system.

- **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,[18] all of the non-latching equipment[19] is function tested; all rams, annulars, and valves are closed and opened to confirm that they are capable of operating if required. Every 14 days,[20] all pipe rams, annulars, valves, and the choke manifold are pressure tested. Every 21 days, the acoustic

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[18] 30 CFR 250.737 and API Standard 53 section 7.6.5.1.3.

[19] 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.

[20] 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).

batteries are checked,[21] and the shear rams are pressure-tested.[22] 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.[23] 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.

Events by Operational State

Analyzing in-operation events separately from not-in-operation events presents a more realistic picture of the risks and how WCE is employed to manage them. Not in operation means that the equipment is being maintained, inspected, or tested before use, presenting lower safety and environmental risk than equipment that is in use. It is not until the BOP stack has been connected to the wellhead and all of the initial subsea testing has been completed that the system is in operation and well construction begins.

A comparative analysis was performed to evaluate the relationship between not-in-operation events and the risk of a more serious in-operation event such as a stack pull. A reporting ratio was calculated for each rig with activity (BOP days) and adjusted using stack runs as a surrogate measure of rig activity to compare rates of reported not-in-operation events between rigs:

$$\text{Adjusted reporting ratio for Rig "A"} = \frac{\text{Rig A's proportion of not-in-operation events}^{24}}{\text{Rig A's proportion of stack runs}^{25}}$$

Figure 5 shows the ratio for each rig, calculated using 2019 data. The line intersecting the graph at the value of 1.0 represents the baseline reporting ratio where a rig's not-in-operation event

[21] API Standard 53 table 7.

[22] 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 table 10.

[23] API Standard 53 table 7.

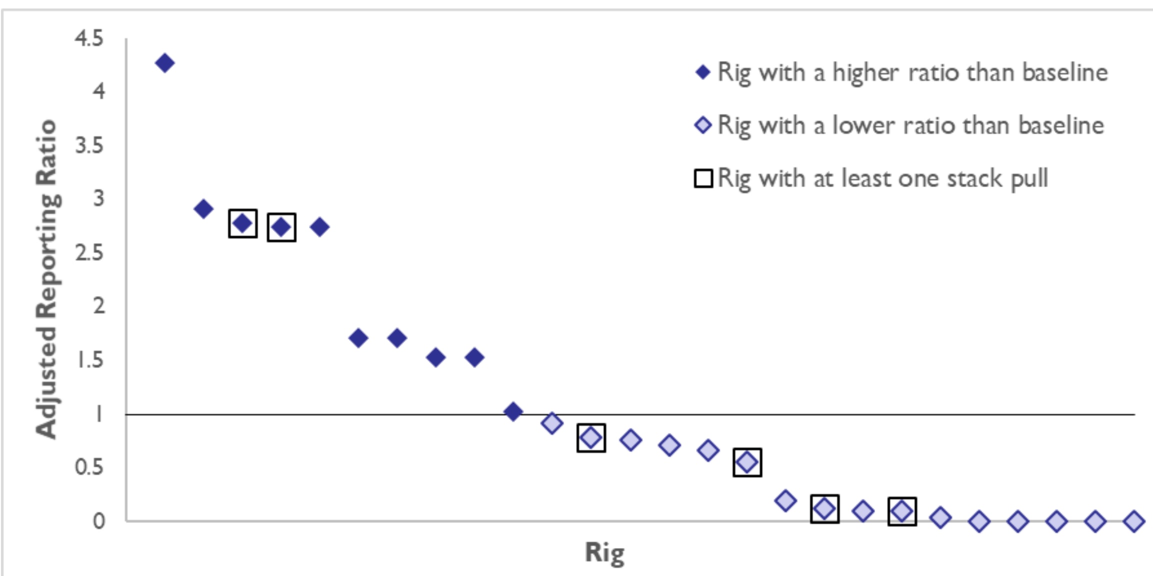
[24] Rig A's not-in-operation events divided by the total not-in-operation events for all rigs.

[25] Rig A's stack runs divided by the total stack runs for all rigs.

reporting is proportional to its level of activity relative to other rigs with reported events. A ratio greater than 1.0 indicates potentially disproportionately high reporting of not-in-operation events, and similarly, a ratio less than 1.0 indicates potentially disproportionately low reporting of not-in-operation events. As shown in the figure, 10 rigs are above the baseline, and 16 rigs are below it.

Figure 5 also shows which rigs experienced stack pulls (shown as an overlaid, outlined shape). Of the 10 rigs with higher relative reporting of not-in-operation events, two experienced at least one stack pull (20.0 percent). Of the 16 rigs with lower relative reporting of not-in-operation events, four experienced at least one stack pull (25.0 percent). Considering all stack pulls, the number that occurred on rigs below the baseline (six) was three times the number that occurred on rigs above the baseline (two). This analysis provides support for an inversely proportional relationship between not-in-operation events and the occurrence of a stack pull (i.e., more not-in-operation events found might lead to fewer stack pulls).

Figure 5: Subsea System Not-in-Operation Events Relative to Rig Activity, 2019



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

Events by Subunit

WCE, for purposes of this report, is broken down into the following system subunits: auxiliary equipment, BOP controls, BOP stack, diverter, choke and kill, and riser. An overview of each subunit, and the included components, is provided in Appendix F. Table 3 estimates the population of components for each subsea subunit at work in 2019 to put the event proportions into perspective. A rig with two BOP stacks does not have twice as many components as a one BOP stack rig because in either case, only one riser, diverter, choke manifold, and auxiliary equipment subunit is needed; the additional components are attributed mainly to the BOP controls and BOP stack subunits. The details of these estimations are shown in Appendix E.

Generally, subunits with more components have more failures, and reported events support this. Table 4 and Table 5 show that the BOP control systems, which have the most redundancies and are grouped in the charts because they use many similar components, carry the greatest numbers of events. BOP control system hydraulic and electronic components are predominantly non-metallic or electronic, and they are relatively fragile compared to the drilling equipment. This, together with the high function test counts for the redundant circuits, partially explains the higher proportion of not-in-operation events attributed to the control systems.

Table 3: Estimates of Subsea WCE Components by Subunit, 2019

SUBUNIT	ONE-STACK SYSTEM		TWO-STACK SYSTEM		Total
	Components	Active Rigs	Components	Active Rigs	Components
BOP CONTROL SUBUNITS					
BOP Primary Control System	1,118	13	1,979	15	44,219
BOP Emergency Control System	133	13	242	15	5,359
BOP Secondary Control System	139	13	276	15	5,947
OTHER SUBUNITS					
Auxiliary Equipment	40	13	42	15	1,150
BOP Stack System	380	13	760	15	16,340
Choke Manifold System	383	13	383	15	10,724
Diverter System	108	13	108	15	3,024
Riser System	788	13	788	15	22,064
TOTAL	3,089		4,578		108,827

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

The BOP stack—which has redundancies in multiple annulars, rams, and side outlet valves, but not in connectors, flex joints, and mandrels—also has a higher proportion of events relative to most other subunits for both in-operation and not-in-operation events. The choke manifold system is both fully redundant and accessible. Neither the diverter system, which is generally accessible, or the riser system, which is not accessible in use, offer any redundancies. No 2019 events were attributed to the auxiliary equipment subunit, which may be due to greater accessibility of this equipment on the rig floor and less frequent need for testing relative to other subunits.[26]

Of course, not all components have the same likelihood of failure, as shown by the riser system population count (Table 3) versus the low event proportion. This can be explained by understanding that the riser system predominantly consists of heavy wall pipes and static seals (as opposed to the dynamic seals on moving pistons, for example), which do not easily break or quickly wear.

Table 4: Not-in-Operation Events by Subunit (Subsea Systems), 2017-19

SUBUNIT	2017-18	2019
BOP CONTROL SUBUNITS		
BOP Primary Control System	65.5%	73.1%
BOP Emergency Control System	6.3%	3.1%
BOP Secondary Control System	3.9%	4.5%
OTHER SUBUNITS		
Auxiliary Equipment	0.1%	0.0%
BOP Stack System	17.4%	16.8%
Choke Manifold System	1.9%	0.4%
Diverter System	1.8%	1.9%
Riser System	3.1%	0.3%

KEY: Not-in-operation
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Table 5: In-Operation Events by Subunit (Subsea Systems), 2017-19

SUBUNIT	2017-18	2019
BOP CONTROL SUBUNITS		
BOP Primary Control System	45.5%	59.3%
BOP Emergency Control System	3.7%	0.9%
BOP Secondary Control System	2.5%	1.9%
OTHER SUBUNITS		
Auxiliary Equipment	2.2%	0.0%
BOP Stack System	9.3%	12.0%
Choke Manifold System	19.5%	6.5%
Diverter System	14.6%	17.6%
Riser System	2.8%	1.9%

KEY: In-operation
SOURCE: U.S. DOT, BTS, SafeOCS Program.

[26] Of the 42 auxiliary equipment components listed in Appendix E, 33 are part of the high-pressure test equipment used mainly for BOP operator tests during annual maintenance procedures. Four of the remaining components are drill-string valves, which are very robust components, and typically accessible and maintained on the rig-floor.

Events by Type

For each event notification, operators select an event type from a component-specific list. For ease of analysis and understanding, similar event types were grouped as shown in Table 6 and Table 7. The tables show a total of 82.6 percent of not-in-operation events and 70.4 percent of in-operation events in 2019 were leaks of some kind. Those leaks are typically the result of worn or damaged elastomeric type seals rather than damage to the more robust steel-based components.

No leaks of wellbore fluids to the environment, classified as losses of containment, were reported to SafeOCS in 2019, and only one such event has been reported since 2017.

The external leaks in Table 6 and Table 7 capture all reported external leaks regardless of the leakage rate (e.g., ten drops per minute from a control valve or fifty gallons per minute from a burst hose would both be shown in the same row as external leaks). All reported external leaks were leaks of a water-based BOP control fluid, not wellbore fluids. Leaks of wellbore fluids would be classified as losses of containment, none of which were reported in 2019, and only one has been reported since the data collection began in 2016. As the external leaks are of hydraulic fluids, rather than wellbore fluids, they typically pose a lower risk to the environment. External leaks do not include venting of BOP fluid into the sea

Table 6: Types of Not-in-Operation Events (Subsea Systems), 2017-19

EVENT TYPE	2017-18	2019
LEAKS		
External Leak	50.0%	61.8%
Internal Leak	25.4%	20.8%
Undetermined Leak	0.1%	0.0%
OTHER		
Communication / Signal Issue	2.7%	2.4%
Electrical Issue	1.4%	2.9%
Fail to Function on Command	2.5%	2.3%
Inaccurate Indication	2.3%	2.4%
Mechanical Issue	13.0%	6.1%
Process Issue	2.5%	1.3%
Unintended Operation	0.1%	0.1%

KEY: Not-in-operation
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Table 7: Types of In-Operation Events (Subsea Systems), 2017-19

EVENT TYPE	2017-18	2019
LEAKS		
External Leak	39.9%	49.1%
Internal Leak	30.7%	21.3%
OTHER		
Communication / Signal Issue	9.6%	6.5%
Electrical Issue	3.7%	6.5%
Fail to Function on Command	3.7%	3.7%
Inaccurate Indication	4.0%	2.8%
Mechanical Issue	5.6%	6.5%
Process Issue	2.5%	3.7%
Unintended Operation	0.3%	0.0%

KEY: In-operation
SOURCE: U.S. DOT, BTS, SafeOCS Program.

during function testing. Such venting is part of the system design and is not the result of an equipment failure event.

Detection Methods

When the equipment is not in operation, it is undergoing both periodic and corrective maintenance. This maintenance includes inspections, before all of the moving parts are function tested and the pressure containing parts are tested to pressures higher than they will be subjected to when in service. As seen in Table 8, corrective and periodic maintenance, inspection, and function and pressure testing (i.e., MIT) account for 76.5 percent of the not-in-operation events. This confirms most events are detected through both routine and preventive maintenance before operations begin.

When BOP equipment is in operation, it remains on standby for a large proportion of the time, with continuous condition monitoring transmitting and recording pressures, volumes, and electrical equipment status. Table 9 shows the portion of events detected while well-construction activities are ongoing. While routine testing also shows relatively high percentages, the actual counts are low (only 11.9 percent of reported events occurred while in operation, as seen in Table 2). On many wells, typically the only use that the BOP stack components get when in operation is the BOP stack's scheduled testing. The BOP stack and control equipment

Table 8: Detection Methods for Not-in-Operation Events (Subsea Systems), 2017-19

	DETECTION METHOD	2017-18	2019
	Casual Observation	8.3%	11.9%
	Continuous Condition Monitoring	4.9%	8.3%
	On Demand	0.5%	1.1%
	Periodic Condition Monitoring	1.5%	2.3%
MIT	Corrective Maintenance	2.3%	0.3%
MIT	Periodic Maintenance	4.9%	7.0%
MIT	Inspection	19.7%	17.6%
MIT	Function Testing	43.0%	35.2%
MIT	Pressure Testing	14.8%	16.4%

KEY: Not-in-operation
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Table 9: Detection Methods for In-Operation Events (Subsea Systems), 2017-19

	DETECTION METHOD	2017-18	2019
	Casual Observation	14.2%	13.9%
	Continuous Condition Monitoring	18.3%	25.0%
	On Demand	1.5%	1.9%
	Periodic Condition Monitoring	7.4%	6.5%
MIT	Corrective Maintenance	0.6%	0.0%
MIT	Periodic Maintenance	0.9%	1.9%
MIT	Inspection	17.0%	18.5%
MIT	Function Testing	14.6%	17.6%
MIT	Pressure Testing	25.4%	14.8%

KEY: In-operation
SOURCE: U.S. DOT, BTS, SafeOCS Program.

undergo a weekly function test and periodic pressure testing, while sensors continuously monitor pressures, temperatures, and current.

Root Causes

A failure is any condition that prevents the equipment from meeting the functional specification, and the root cause is the fundamental reason the failure occurred. If the component failure being addressed is part of a wider event, then the appropriate investigative procedure for that wider event will need to be followed in addition to the individual component failure analysis.

The root cause selections listed in Table 10 and Table 11 can be broadly grouped based on the parties involved:

- Design issue and QA/QC manufacturing are typically attributable to the OEM.
- Maintenance error and procedural error are typically attributable to the equipment owner or operator.
- Documentation error (e.g., an incorrect torque or pressure rating in a document) could be attributable to the OEM, equipment owner or operator, or a third party.
- The remainder of the root cause selections vary as to the parties involved.

The root cause of an event is typically determined by the rig's subsea engineer on-site. If additional investigation is carried out resulting in a change to the original root cause, the SafeOCS record is updated to reflect the new information. The root cause distributions shown in Table 10 and Table 11 reflect the latest information received on the root cause of an event.

As in past years, the root cause of wear and tear was selected for a high percentage of subsea system events relative to other root cause selections. It should be selected only when a component fails after reaching the end of its expected life. For instance, a component with a five-year[27] design life that fails after 60 months in use would properly be considered wear and tear. If it fails on the day before the 60-month mark, then design, maintenance or procedural

[27] Five-years is selected as the example life to tie-in with the API S53 requirement of a 5-year major inspection of the WCE.

errors should be seriously considered. In other words, abnormal wear should not be classified as wear and tear and should be further evaluated to determine the root cause. It is likely that at least some of the failures reported as wear and tear cannot be explained solely as normal wear, discussed further below.

The proportions of events with design issue or QA/QC manufacturing root causes could be expected to decrease as equipment gets older and improved designs are available to the industry. However, it does not always make sense for working components to be replaced simply because a new design is available. Some improvements may take a full five-year maintenance cycle or longer to be adopted and implemented by the equipment owner.

The root causes of maintenance error and procedural error were reported for higher percentages of not-in-operation events (Table 10) compared to in-operation events (Table 11), which is aligned with the fact that maintenance is conducted when not in operation. The selection of assessment pending is greater for in-operation events because many components of subsea WCE systems are inaccessible during operations.

SafeOCS subject matter experts review event notifications in detail and have found that the submitted information does not always provide adequate or meaningful support for the reported root cause. In these cases, either the submitted information is insufficient to support any root cause determination, or the submitted

Table 10: Root Causes of Not-in-Operation Events (Subsea Systems), 2017-19

ROOT CAUSE	2017-18	2019
Design Issue	13.8%	19.6%
QA/QC Manufacturing	9.6%	6.3%
Maintenance Error	11.4%	13.0%
Procedural Error	2.8%	13.9%
Documentation Error	0.4%	0.1%
Wear and Tear	55.8%	44.6%
Other	0.5%	0.1%
NOT DETERMINED		
Inconclusive	0.0%	0.4%
Assessment Pending	4.1%	1.8%
Not Reported	1.6%	0.3%

KEY: Not-in-operation
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Table 11: Root Causes of In-Operation Events (Subsea Systems), 2017-19

ROOT CAUSE	2017-18	2019
Design Issue	15.8%	20.4%
QA/QC Manufacturing	4.0%	5.6%
Maintenance Error	6.2%	6.5%
Procedural Error	4.0%	8.3%
Documentation Error	1.2%	0.0%
Wear and Tear	53.3%	49.1%
Other	0.6%	0.9%
NOT DETERMINED		
Assessment Pending	11.8%	9.3%
Not Reported	3.1%	0.0%

KEY: In-operation
SOURCE: U.S. DOT, BTS, SafeOCS Program.

information suggests that a different root cause should have been selected. Many, but not all, events in the former category are reported as wear and tear events. Cases in the latter category could be due to unclear definitions of some root causes, and better guidance may be needed. SafeOCS tracks cases that fall in these categories and will conduct further analysis. This is an area for further consideration and improvement in the data collection.

Accelerated Failure

Unpredictable wear, i.e., failure of a component before the end of its expected life, can hinder events from being detected and corrected during planned MIT periods before the equipment goes into operation. It can also indicate that design, manufacturing, or procedural changes may be required to prevent similar events.

The expected life varies for different component types, expected installation environments, and other variables. SafeOCS developed the following criteria as a starting point for determining whether a failure occurred earlier than expected, referred to in this report as an *accelerated failure*. These criteria are preliminary and will be modified and refined with input from original equipment manufacturers (OEMs). For purposes of this report, a failure event is determined to be accelerated when any part of the component fails within the following periods or use:

- Closed fewer than 50 times, for an annular or ram packer.
- Less than one year from installation (new or refurbished), for any component.
- Less than two years from installation (new or refurbished), for electronic equipment (e.g., PLCs, circuit boards, power supplies, displays, cables) and non-metallic hose excluding terminations.
- Less than five years from installation (new or refurbished), for metallic components (e.g., wear plates, fasteners, springs, shafts, pistons, cylinders, hose terminations).
- Less than 10 years from initial installation, for major components (e.g., forgings, BOP bodies, valve bodies, bonnets, C/K spools, ram blocks).

Table 12 shows the components with the most events determined to be accelerated after applying these criteria. For the events considered accelerated, wear and tear was the most commonly reported root cause of solenoid hydraulic valve and slide shear seal / SPM valve failures, and design issue and procedural error were the most commonly reported root causes of regulator failures. SafeOCS will publish updated data on accelerated failures after the criteria are revised.

Table 12: Events Considered Accelerated, per Preliminary Criteria, 2019

	COMPONENT	Regulator	Solenoid Valve Hydraulic	Slide Shear Seal Valve or SPM Valve
	Events Considered Accelerated	107	79	57
ROOT CAUSE	Design Issue	33.6%	-	15.8%
	QA/QC Manufacturing	5.6%	3.8%	1.8%
	Maintenance Error	7.5%	12.7%	15.8%
	Procedural Error	31.8%	25.3%	15.8%
	Documentation Error	-	-	1.8%
	Wear and Tear	19.6%	57.0%	49.1%
	NOT DETERMINED			
	Assessment Pending	1.9%	1.3%	-

NOTE: Components with >50 events considered accelerated are shown. Shear seal valves and SPM valves are grouped as they fulfill the same tasks.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Stack Pulls

All stack pulls are, by definition, in-operation events. The event types attributed to subsea stack pulls over the last three years are shown in Table 13. Subsea stack pulls occurred for eight of 108 in-operation events in 2019. They occur only if the equipment cannot be repaired in place or if redundant equipment would not support continuing operations without the failed component. All of the 2019 stack pulls were a result of control fluid leaks.

Events that occur prior to the stack being latched up to the wellhead and passing all initial latch-up testing are considered not-in-operation events and can result in the BOP stack being retrieved to the surface for component repair or replacement. Such stack retrievals are not considered stack pull events.

Table 13: Types of Events Leading to Subsea Stack Pulls, 2017-19

EVENT TYPE	2017-18	2019
LEAKS		
External Leak	8	6
Internal Leak	4	2
OTHER		
Communication / Signal Issue	1	-
Fail to Function on Command	2	-
Mechanical Issue	2	-
Process Issue	1	-
TOTAL	18	8

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

Root Causes of Subsea Stack Pulls

Table 14 shows the distribution of root causes for events leading to subsea stack pulls. Maintenance error or procedural error were attributed to three subsea stack pulls in 2019. It is of concern that any stack pull events were attributed to wear and tear, because components adjudged to be vulnerable for the duration of the upcoming well should have been replaced during MIT before deploying the BOP stack. For three subsea stack pulls in 2019, the root cause was not reported due to a pending investigation, and SafeOCS has not received additional investigation information.

Table 14: Root Causes of Subsea Stack Pulls, 2017-19

ROOT CAUSE	2017-18	2019
Design Issue	6	-
QA/QC Manufacturing	1	-
Maintenance Error	1	2
Procedural Error	3	1
Wear and Tear	2	2
NOT DETERMINED		
Assessment Pending	5	3
TOTALS	**18**	**8**

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

Stack Pull Combinations

Table 15 shows the components and event types for events leading to subsea stack pulls in 2019. Of the eight stack pulls, two are attributed to the consumable ram and annular packers leaking internally, which is the expected failure mode for these components. All rigs with subsea BOP stacks working in the GOM in 2019 had two annular BOPs, though only one is required,

Table 15: Component Combinations Associated with Reported Subsea Stack Pulls

ITEM	COMPONENT	EVENT TYPE	Total In-Op. Events	Stack Pulls
Annular Preventer	Packing Element	Internal Leak	5	1
BOP Control Pod	Piping / Tubing	External Leak	3	1
	SPM Valve	External Leak	3	1
BOP Controls, Stack Mounted	Hose	External Leak	7	1
	Piping / Tubing	External Leak	1	1
Pipe Ram Preventer	Ram Block Seal	Internal Leak	2	1
Stack C/K System	C/K Valve	External Leak	1	1
	Flex-loop Hose	External Leak	2	1
TOTALS			**24**	**8**

KEY: In-operation
SOURCE: U.S. DOT, BTS, SafeOCS Program.

which suggests that other issues, such as the gas bleed valves'[28] location, could have influenced the decision to pull the BOP stack. The decision to pull the stack for the ram block seal could have involved one of several pipe ram sizes or types. Pipe rams are often, but not always, protected by more than the minimum levels of redundancy, which require that the BOP stack is equipped with two pipe rams capable of sealing on each pipe size in use.[29] Overall, the eight subsea stack pulls are equally divided between the BOP stack (annular preventer, pipe ram preventer, and stack choke and kill system) and the BOP control systems (control pod and stack mounted controls).

Summaries of the 2019 subsea stack pull events can be found in Appendix D.

Investigation and Analysis

SafeOCS categorizes investigation and failure analysis (I&A) into three levels: cause immediately known, subject matter expert (SME) review (performed by rig personnel), and root cause failure analysis (RCFA).[30] 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 needed to determine the root cause. An I&A is categorized as a SME review when the cause of the failure is questionable, and the investigation does not rise to the level of an RCFA. An RCFA is a more detailed investigation typically conducted for more significant events, and it must involve either the original equipment manufacturer or a qualified third party.

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[28] Gas bleed valves are connected to the BOP stack below an annular preventer. If the connection is under the lower annular, then the bleed valves can be used to evacuate any gas from below either annular. If they enter the BOP stack below the upper annular, they can be used only if the upper annular is in good working order.

[29] 30 CFR 250.730(a)(1) and API Standard 53 section 7.1.3.1.6. Compliance with this requirement could involve having, for example, one set of 5-1/2" fixed pipe rams, one set of 6-5/8" fixed pipe rams, and one set of 5" to 7" variable bore rams where the variable bore rams provide the redundancy for both of the other sizes. BOP stacks with greater than the minimum required number of ram cavities (guide chambers) typically have more than the required redundancy.

[30] For I&As at the SME review level, the SMEs referred to are those who performed the investigation and are employed by the rig or operator. The term does not refer to SMEs retained by SafeOCS as part of the SafeOCS review team.

I&A information was received for 172 of 907 subsea system events.[31] Of the 98 I&As pertaining to these events (one investigation can involve multiple events), 20 were at the RCFA level, 33 were at the SME review level, and the remainder were for events with immediately known causes. Preventive actions were provided for all RCFAs and some SME review and cause immediately known I&As. Table 16 (page 30) summarizes the findings for I&As that included preventive actions pertaining to 124 events, grouped according to the component issue.[32] Of the 124 events, 114 occurred while not in operation. In the table, the items corresponding to the 10 in-operation events are marked with an asterisk.

The events in item 31 of Table 16, reported for hydraulic pressure regulators, shear-seal valves, and solenoid valves, resulted from a change in the procedures by one equipment owner to incorporate deionization in making and treating the potable water onboard its fleet. A rig's potable water system is used for water applications throughout the rig, from cooling the engines and supplying the laundry, kitchen, and bathrooms to creating the BOP fluid, each of which may favor different properties that should be managed. RCFA findings indicated that the deionized water created a reactive environment (a lower pH possibly) that caused the nickel binding agent to leach from the tungsten carbide coating on the components' seal plates. This issue is discussed further below under *Subsea System Lessons Learned*.

Subsea System Lessons Learned

Several observations can be made regarding BOP control fluid issues reported in 2019. BOP control fluid is made on the rig, typically from 97.0 percent fresh water mixed with a specially formulated concentrate. There are various suppliers of these concentrates, but they all formulate their products to meet U.S. EPA toxicity requirements specified in NPDES permits for subsea control fluids. These standards are necessary because most subsea BOP control systems are designed to vent-to-atmosphere the fluids used. After the mixed fluid has been used on the BOP stack, it is expelled into the ocean. As water is the prime ingredient, the

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31 The total includes 45 investigated events that also benefitted from the findings of another I&A for a similar issue, and two events without a submitted investigation report but that benefitted from the findings of another I&A for a similar issue.

32 In the table, one row comprises one or more events and may reflect multiple I&As.

water must meet the criteria specified by the fluid concentrate manufacturer. The equipment owner's maintenance procedures include checking the water's properties and the mixed BOP fluid regularly.

Problem 1. Nickel Leaching.

In an attempt to meet the water criteria, one equipment owner in 2018–19 changed their water treatment procedures to demineralize the water. While this in itself is not a problem, as the potable water is also used for drinking, cooking, and washing, this change coincided with an equipment improvement from one of the BOP control valve OEMs. The OEM substituted tungsten-carbide for the previously used Stellite for hard-facing seal plates in regulators and shear seal valves. The OEM had issued a bulletin specifying BOP control system water specifications before making the wholesale material change.

Submerging the tungsten-carbide coated seal plates in the demineralized water caused the leaching of nickel, the binding agent for the tungsten carbide coating. This leaching process degraded the coatings and corroded the components' internal parts (pitted and porous seal plates), causing failure, which would not have occurred if the water used to mix the BOP fluid had met the concentrate manufacturer's published specification.

Problem 2. Calcium Soap

There were reports of what was described as calcium soap buildup in some BOP control systems, visible in the tank and causing problems around the valve seal plates in particular. One of the chemicals used to disinfect drinking water on a rig is calcium hypochlorite, commonly used in public swimming pools. This build up appears to be a problem with only one of the major brands of BOP concentrate. The company issued an alert in 2013 stating that under no circumstances should the concentrate be mixed with calcium hypochlorite.

Solution

The solution to both of these problems is the same: Ensure that the water supplied to the BOP fluid mix system meets the specifications required by both the WCE manufacturer and the BOP fluid concentrate manufacturer.

Table 16: Findings from I&As for Subsea System Events, 2019

	ROOT CAUSE	ROOT CAUSE DETAILS	RECOMMENDED FOLLOW-UP ACTION
1*	Design Issue	BOP control pod SPM valve found leaking by ROV 3 months after a seal kit was installed. D&I found the spool worn.	Equipment owner considering shortening the time between rebuilds.
2	Design Issue	C/K outer gas bleed valve was malfunctioning (tail rod moving very slowly) after 1 month of service. RCFA found that a design issue allowed pressure build-up behind the o-ring, forcing it out of its groove in the event of a sudden release of pressure in the hydraulic chamber. The seals trapped pressure and increased friction.	OEM to replace seals with new LCD (lip cut double) seals in the gate valve operator. OEM issued a product bulletin.
3	Design Issue	Casing shear ram bonnet leaked at the bonnet end flange. Analysis indicated issues with the seal design on specific bonnet models.	The OEM has released new designs or endcap and bonnet end seals to alleviate this issue. Owners of such equipment are encouraged to update at the next convenient opportunity.
4	Design Issue	CSRs ram block retainer bolt was sheared when opening the rams after 5 months of service, D&I found barite packed behind ram blocks.	OEM to modify design to displace the barite.
5	Design Issue	In preparation for deployment pressure tests, crew was unable to fill the choke line with water due to an issue preventing the stack mounted valves from reliably closing, and therefore sealing. Valves had been recently remanufactured by the OEM, and D&I found all pistons were missing wear bands.	The OEM has redesigned the wear band to make it easier to install and has rescinded the internal permission to leave them out. The piston seals have also been redesigned and a product bulletin issued recommending upgrading to the new seals at the next maintenance cycle.
6	Design Issue	Non-shear acoustic ROV panel tubing disconnected due to water hammering effects after seven days of service.	Rig owner to use tubing clamps to reduce damage.
7	Design Issue	Packers failed on BSR, and inspection showed delamination of packers. OEM analysis determined the cause of the delamination to be a design issue.	Equipment owner changed operational procedures to reduce the number of cycles during testing until a redesigned product is available.
8	Design Issue	SPM manifold interface seal leaked after 7 months.	Equipment owner to ensure correct torque procedure is used when installing valves on interface seals.
9	Design Issue	Subsea pod packers leaked due to a lack of axial squeeze, which the OEM RCFA determined can be caused by many contributing factors including standoff and packer thickness.	Several procedural actions taken by the equipment owner. The OEM to complete an assembly test of all variables and their effect on seal-ability.
10*	Design Issue	Supply side of the flowline seal regulator leaked after 2 months of usage. RFCA determined the cause to be high vibration within the piping system.	Equipment owner upgrade planned to reroute tubing to effectively utilize the accumulator and install check valves to stabilize the system.

	ROOT CAUSE	ROOT CAUSE DETAILS	RECOMMENDED FOLLOW-UP ACTION
11*	Design Issue	The DCP (driller's control panel) solid state hard drive failed due to excessive rewriting to the same space in memory. This appears to have been an inadvertent side effect of removing 'Enable' button functionality from the supervisor control panel, to disable control from the subsea office. This disabling caused error messages to continuously write to all control panels.	Equipment owner to install larger and more durable SLC (single-level cell) hard drives, install SSD (solid state drive) health monitoring software, and update maintenance procedures to include recording SSD health monitoring information, throughout equipment owner fleet, to give the OEM time to correct software issue involving erroneous error messages.
12	Design Issue	The lower inner kill valve stem packing leaked after 4 months, and the stem packing was found to be damaged. The tail rod was found to be in good condition.	OEM proposed a redesign of the valve.
13	Design Issue	Weld broke at the piping / tubing connection on the stack-mounted BOP controls after 39 months of operation. RFCA including metallurgical analysis determined cause to be vibration-induced fatigue.	OEM to recommend a support bracket to mitigate vibration.
14	Design Issue	Wellhead connector regulator was noted to be leaking after twenty-one months of service. A design issue for the flange o-ring was noted.	Wellhead connector regulator flange o-ring is a known design issue, and an OEM engineering upgrade is pending.
15	Design Issue	While checking the torque on the 1/4" stainless steel socket head cap screws for the compensated chamber solenoid valve housings, found 2 of the 7 fasteners snapped off at the shoulder. The 304 SS (stainless steel) bolts deemed to be unfit for this service by the OEM.	OEM has issued a bulletin and will provide replacement bolts to the equipment owners.
16	QA/QC Manufacturing	A new stainless steel filter bowl could not be unscrewed from its housing due to galled threads.	OEM to ensure all filter housings are checked for damage and galling prior to signing off and shipping to rigs.
17	QA/QC Manufacturing	C/K flex loop / hose liner cracks developed following pressure testing. OEM analysis determined the cracking issue to be a QA/QC manufacturing issue and issued information bulletin.	Per information bulletin, equipment owners should preemptively replace hoses that were manufactured during the specified period.
18	QA/QC Manufacturing	The end connection of the BOP leaked due to paint on the mating surface preventing face to face contact.	OEM manufacturing to review the current masking and painting process to ensure the contact surfaces are free of any paint.
19	Maintenance Error	A pod packer seal leaked; the investigation determined that it had been incorrectly installed.	Equipment owner to follow the internal technical bulletin created for this incident and distributed throughout equipment owner fleet.
20	Maintenance Error	After 15 months, a gas valve leaked. D&I found the o-ring disintegrated (dry rotted) as a result of applying improper lubricant.	Equipment owner to ensure the crew is aware of the proper installation procedure for charging valves.

	ROOT CAUSE	ROOT CAUSE DETAILS	RECOMMENDED FOLLOW-UP ACTION
21	Maintenance Error	Contamination created a loss of seal of the conduit flush SPM valve. D&I revealed radial abrasions and pitting on the upper seal seat and the spool showed signs of discoloration from fluid wash.	Equipment owners should try to keep the riser conduit lines clean when they are stored on deck or in transit.
22	Maintenance Error	Seals on BOP control pod receptacle leaked after a storm related LMRP disconnect, due to the OEM using a standard, as opposed to a stack-specific, jig for alignment during factory based maintenance, exacerbated by the receptacle not being correctly preloaded.	Equipment owner to include procedures in well integrity management system for BOP control pod alignment checks when control pods are installed in a new position or alignment components are repaired.
23	Maintenance Error	Supply pipe from pod to connector was seen to leak. Investigation found the code 62 flange bolts loose causing a leak past the o-ring seal.	The equipment owners' between well maintenance should include checking piping connections.
24	Maintenance Error	The flange connection between two close-coupled stack mounted kill valves leaked immediately after installation due to improper procedures.	Equipment owner should ensure procedures dictate that the vertical connection between close coupled valves and spools are correctly made up before the horizontal connections to the BOP stack.
25	Maintenance Error	Visual by ROV on tail rod indicator showed that the mud boost valve did not travel to the full close position. D&I report stated that the actuator was incorrectly set with the drift-stop.	OEM recommends following procedures.
26	Maintenance Error	Water ingress into PBOF (pressure balanced, oil-filled) cable after 13 months of usage. Locking collar was found to be slightly under-torqued.	Equipment owner to follow proper maintenance procedures.
27*	Maintenance Error	With BOP on surface, testing could not replicate suspected pilot operated check valve (POCV) internal leakage.	Equipment owner decided to replace all POCVs with upgrade based on recent product bulletin.
28*	Procedural Error	A hydraulic leak was observed when the lower annular was closed. Investigation found a loose fitting of the hose from the control pod to the shuttle valve possibly caused by torsion in the hose reacting on the fitting, but also the hose being longer than needed.	Equipment owner to shorten hydraulic hose to remove excess length, inspect all hoses and connections on both pods, and train on proper hose practices.
29*	Procedural Error	Diverter assembly flowline seal leaked after 30 days usage. RCFA found gaps in installation procedure.	Equipment owner to develop revised installation procedure.
30	Procedural Error	Inadequate procedural constraints concerning allowable weight down permitted miscommunication which resulted in the tension reduction being miscalculated. When the ROV initiated the unlatch there was insufficient support, and the BOP stack tipped over.	Equipment owner has limited weight down to an empirical number based on past successes, while they investigate and implement an alternative maximum limit that works across their fleet.

	ROOT CAUSE	ROOT CAUSE DETAILS	RECOMMENDED FOLLOW-UP ACTION
31*	Procedural Error	Regulators, shear seal valves, and solenoid valves that leaked had evidence of nickel leaching damage to the Tungsten-Carbide seal plates. Nickel leaching is a result of the use of demineralized water in the BOP control fluid.	Equipment owner to implement a water-hardening system and use water that has not been fully deionized as a base for the control fluid.
32	Wear and Tear	Annular segments observed protruding approximately 5" into the bore. OEM RFCA found all material properties within their specifications.	OEM planned redesign to improve performance and life.
33*	Wear and Tear	BOP stack choke valve failed to open after having been in use for 72 months. Wrote MOC to continue operations. When pulled, found defective adjustable orifice.	Equipment owner to check adjustable orifice during between-well maintenance.
34	Wear and Tear	BOP stack wellhead connector gasket retainer cylinder would not hold pressure after 6 months of operation. Damaged o-ring found. Root cause reported as wear and tear.	Equipment owner to consider adding a formal test of the gasket retainers between wells.
35*	Wear and Tear	Conduit SPM valve cap leaked. Upper Delrin seat was found to be cracked after 5 months of operation.	Equipment owner replaced Delrin seat with upgraded brass seat as referenced in previously published OEM bulletin.
36	Wear and Tear	During latch-up testing of deadman system, casing shear ram high pressure hose found ruptured. Hose was mechanically damaged with torn outer sheath causing wire reinforcement to corrode and compromising hose integrity.	Equipment owner to take better care of hoses and complete a more thorough inspection when examining hoses.
37	Wear and Tear	Kill isolation valve operator leaked after 54 months of use. D&I found material degradation of the cylinder and worn piston seals.	Equipment owner to perform valve maintenance as specified in maintenance procedures. Perform thorough inspections during equipment maintenance.
38	Wear and Tear	Surface flowmeter was not functioning and meter turbine was damaged.	Equipment owner should check filters for integrity as turbine damage is usually the result of impact by a foreign body.
39	Inconclusive	While pressure testing the mandrel to upper double BOP connection, there were leaks from side entry outlets. After new gaskets were installed, the side outlets leaked again. The grooves were then dressed with fine emery cloth after the surface finish of the grooves was questioned. The 5-why RCFA was inconclusive.	OEM to ensure all critical surface finish levels are inspected as required. Procedure has been updated to call-out the inspection of the ring groove surface finish and operators have been re-trained / refreshed accordingly.

SOURCE: U.S. DOT, BTS, SafeOCS Program.
NOTE: *Indicates in-operation event. For item 31, one component event was in operation and the remainder were not in operation.

CHAPTER 3: SURFACE WCE SYSTEM EVENTS

Table 17: Surface System Numbers at a Glance, 2017-19

MEASURE	2017	2018	2019
ACTIVITY			
Wells with Activity	160	217	203
Wells Spudded	65	86	86
RIGS			
Rigs with Activity	28	28	35
Rigs with Reported Events	18	16	15
OPERATORS			
Active Operators	19	24	22
Reporting Operators	10	8	9
BOP DAYS			
Total BOP Days	5,172	6,943	6,969
In-Operation BOP Days	3,641	5,043	5,134
Not-in-Operation BOP Days	1,531	1,900	1,835
COMPONENT EVENTS			
Total Events Reported*	114	69	87
In-Operation Events	57	35	44
In-Operation Event Rate	15.7	6.9	8.6
In-Operation Events per Well	0.4	0.2	0.2
Not-in-Operation Events	57	34	43
Not-in-Operation Event Rate	37.2	17.9	23.4
Not-in-Operation Events per Well	0.4	0.2	0.2
BOP STACK MOVEMENTS			
Total Stack Starts	186	224	224
Successful Starts	170	217	196
Stack Pulls**	10	10	36**
LOC EVENTS			
Loss of Containment Events	0	0	0

KEY: In-operation Not-in-operation

NOTES:

* Total Events Reported excludes any events identified in WAR data.

** For 2019, the number of stack pulls includes 16 such events identified in WAR.

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

Table 17 lists measures related to all GOM OCS *surface* wells undergoing activity, together with event data, during each of the last three years. Overall, 87 events were reported for surface WCE systems in 2019, equating to 8.8 percent of all events.[33] As in previous years, events were relatively evenly split between operational states, with 44 events occurring while in operation and 43 while not in operation.

Of the 44 reported in-operation events, 20 (45.5 percent) resulted in a stack pull. An additional 16 surface stack pulls not reported to SafeOCS were identified in WAR data for a total of 36 known surface stack pull events in 2019.[34] About 18.4 percent (36 of 196) of successful surface BOP stack starts—meaning the stack was assembled

33 87 / 994. The total number of reported events can be found in Table 1.

34 All *subsea* stack pulls identified in WAR data were reported to SafeOCS.

on the wellhead and went into operation—eventually led to a stack pull in 2019. Excluding the stack pulls identified in WAR, 10.2 percent (20 of 196) of stack starts eventually led to a stack pull in 2019, compared to 4.6 percent (10 of 217) in 2018.

Ten-fold fewer events were reported for surface systems than for subsea systems in 2019, though more surface wells than subsea had activity. Table 17 shows that from 2018 to 2019, there were 14 fewer wells with activity, and total surface BOP days remained about the same, with a fleet seven rigs larger. In 2019, surface system rigs conducted well operations on an average of 5.8 wells per year (compared to an average of 6.5 wells per year for subsea system rigs) at about 10.9 percent fewer in-operation days per well.[35] There were 224 total surface BOP stack starts and 196 successful stack starts for 203 wells with operations in 2019.

Event rates were also calculated for surface WCE systems; however, their usefulness in evaluating potential trends is limited by the low count of reported events. The surface system event rates in Table 17 show that approximately 8.6 in-operation events occurred per 1,000 in-operation BOP days (a 24.6 percent increase from 2018 to 2019), and approximately 23.4 not-in-operation events occurred per 1,000 not-in-operation BOP days (a 30.7 percent increase from 2018 to 2019).

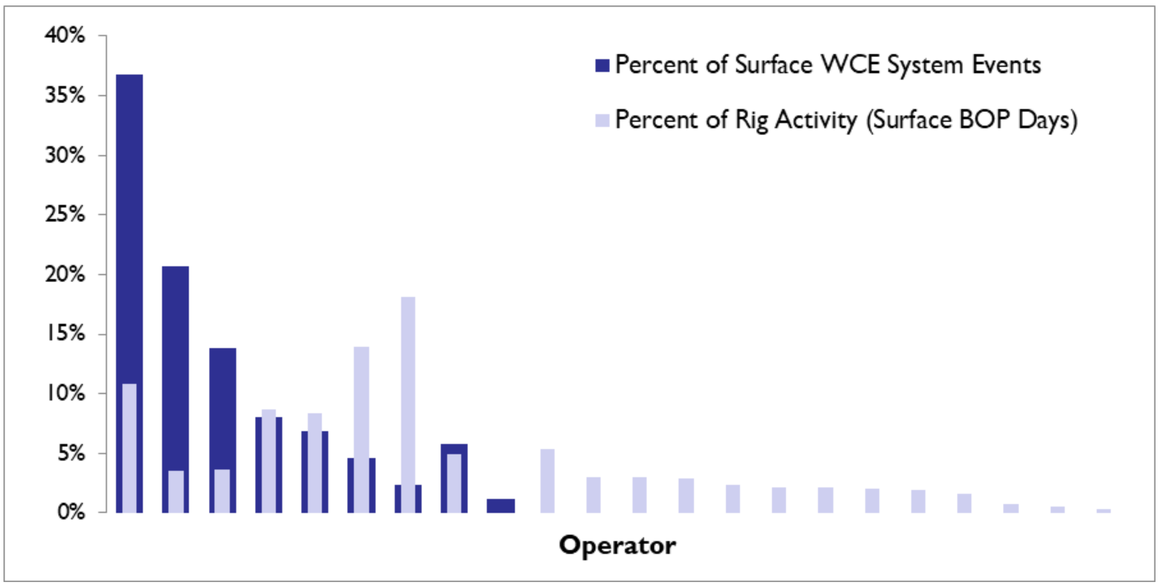
As with event rates, the usefulness of the events-per-well measures is limited by the low count of reported events for surface WCE systems. On a per well basis, Table 17 shows that approximately 0.2 in-operation and 0.2 not-in-operation events were reported per surface well with activity. Less than one event per well with activity was reported during each of the last three years, for both in-operation and not-in-operation events.

[35] Subsea WCE systems: 5,160 in-operation BOP days / 182 wells with activity = 28.4 days / well. Surface WCE systems: 5,134 in-operation BOP days / 203 wells with activity = 25.3 days / well.

Reporting Operators

Figure 6 shows surface system events and rig activity (measured in BOP days) for the 22 active operators in 2019. The rig activity for any one operator may come from multiple rigs. Overall, reporting levels for surface systems remain below 50.0 percent of active operators and active rigs. In 2019, nine of the 22 (40.9 percent) active surface system operators submitted event notifications, and 15 of 35 (42.9 percent) active surface rigs were represented in event reporting.

Figure 6: Surface System Events and Rig Activity by Operator, 2019



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

Operational States of 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 considered to be in operation once the BOP stack has been assembled on the wellhead and all of 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 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 are unlikely to be reported to SafeOCS.

Since WCE on surface system rigs is accessible on deck throughout operations, 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.

Events by Subunit

Table 18 estimates the population of components for each of the surface subunits at work in 2019 to put event proportions into perspective. The details of these estimations are shown in Appendix E. Surface WCE systems are less complex, as redundancy of control circuits and components is not necessary since the equipment is readily accessible at all times; thus, the BOP stack and BOP controls component counts are very different from the subsea systems. While

Table 18: Estimates of Surface WCE Components by Subunit, 2019

SUBUNIT	Components	Active Rigs	Total Components
BOP CONTROL SUBUNITS			
BOP Primary Control System	143	35	5,005
OTHER SUBUNITS			
Auxiliary Equipment	34	35	1,190
BOP Stack System	141	35	4,935
Choke Manifold System	383	35	13,405
Diverter System	107	35	3,745
Riser System*	0	35	0
TOTAL	808		28,280

NOTE: *The surface system riser equivalent is the diverter overshots and spools, which are quantified with the diverter system.
SOURCE: U.S. DOT, BTS, SafeOCS program.

the auxiliary equipment, choke manifolds, and diverters are generally comparable with their subsea counterparts, a surface system does not have an equivalent riser system.[36]

Tables 19 and 20 show that, in general, the subunits with the most components carry the greatest numbers of events, with most events from 2017-19 attributed to the BOP control, BOP stack, or choke manifold systems. Fewer choke manifold system events were reported in 2019 compared to previous reporting years.

Table 19: Not-in-Operation Events by Subunit (Surface Systems), 2017-19

SUBUNIT	2017-18	2019
BOP CONTROL SUBUNITS		
BOP Primary Control System	22.0%	44.2%
OTHER SUBUNITS		
Auxiliary Equipment	5.5%	2.3%
BOP Stack System	51.6%	46.5%
Choke Manifold System	18.7%	2.3%
Diverter System	0.0%	0.0%
Riser System*	2.2%	4.7%

KEY: Not-in-operation
NOTES:
* For component population estimates, SafeOCS quantifies riser system components with the diverter system.
- For 2019, the percentages refer to the total reported events. Stack pull events identified in WAR are excluded.
SOURCE: U.S. DOT, BTS, SafeOCS program.

Table 20: In-Operation Events by Subunit (Surface Systems), 2017-19

SUBUNIT	2017-18	2019
BOP CONTROL SUBUNITS		
BOP Primary Control System	33.3%	38.6%
OTHER SUBUNITS		
Auxiliary Equipment	4.3%	9.1%
BOP Stack System	36.6%	45.5%
Choke Manifold System	25.8%	4.5%
Diverter System	0.0%	0.0%
Riser System*	0.0%	2.3%

KEY: In-operation
NOTES:
* For component population estimates, SafeOCS quantifies riser system components with the diverter system.
- For 2019, the percentages refer to the total reported events. Stack pull events identified in WAR are excluded.
SOURCE: U.S. DOT, BTS, SafeOCS program.

36 A surface WCE system has about 12 overshot spools connecting from the top of the annular to the diverter (counted as diverter system components in Table 18). An additional explanation is provided in Appendix F.

Events by Type

For each event notification, operators select an event type from a component-specific list. For ease of analysis and understanding, similar event types were grouped as shown in Tables 21 and 22. The tables show a total of 86.1 percent of not-in-operation events and 75.0 percent of in-operation events in 2019 were leaks of some kind. Internal leaks within the surface BOP stack typically occur with annular or ram packers at the end of life. External leaks on surface BOP control systems are typically hydraulic oil or pre-mixed water-based fluids. Not all external leaks resulted in the release of fluids to the environment; an event is categorized as an external leak even when the leaked volumes are completely contained onboard the rig. None of the external leaks were leaks of wellbore fluids (i.e., losses of containment).

Table 21: Types of Not-in-Operation Events (Surface Systems), 2017-19

EVENT TYPE	2017-18	2019
LEAKS		
External Leak	30.8%	53.5%
Internal Leak	51.6%	32.6%
OTHER		
Communication / Signal Issue	1.1%	0.0%
Electrical Issue	2.2%	0.0%
Fail to Function on Command	3.3%	2.3%
Inaccurate Indication	0.0%	2.3%
Mechanical Issue	7.7%	7.0%
Process Issue	3.3%	2.3%

KEY: Not-in-operation
NOTE: For 2019, the percentages refer to the total reported events. Stack pull events identified in WAR are excluded.
SOURCE: U.S. DOT, BTS, SafeOCS program.

Table 22: Types of In-Operation Events (Surface Systems), 2017-19

EVENT TYPE	2017-18	2019
LEAKS		
External Leak	29.0%	27.3%
Internal Leak	51.6%	47.7%
OTHER		
Communication / Signal Issue	1.1%	9.1%
Fail to Function on Command	2.2%	6.8%
Mechanical Issue	12.9%	4.5%
Process Issue	3.2%	4.5%

KEY: In-operation
NOTE: For 2019, the percentages refer to the total reported events. Stack pull events identified in WAR are excluded.
SOURCE: U.S. DOT, BTS, SafeOCS program.

Detection Methods

The detection methods listed in Table 23 and 24 show that more than half of surface system events in 2019 were detected through pressure or function testing (55.9 percent of not-in-operation events and 63.6 percent of in-operation events). Pressure testing was the most common detection method for both in-operation and not-in-operation events, which may suggest that for some events a pressure test is operationally preferred (i.e., lower potential to disrupt operations) over inspection to determine equipment condition.

When the equipment is not in operation, monitoring is not realistically applicable, because typically, the power (required for monitoring) has been removed to allow maintenance and inspections to take place. This is seen in the lower percentage of not-in-operation events detected through casual observation and condition monitoring.

Table 23: Detection Methods for Not-in-Operation Events (Surface Systems), 2017-19

	DETECTION METHOD	2017-18	2019
	Casual Observation	7.7%	4.7%
	Continuous Condition Monitoring	5.5%	0.0%
	Periodic Condition Monitoring	0.0%	2.3%
MIT	Corrective Maintenance	0.0%	4.7%
MIT	Periodic Maintenance	0.0%	9.3%
MIT	Inspection	4.4%	23.3%
MIT	Function Testing	18.7%	14.0%
MIT	Pressure Testing	63.7%	41.9%

KEY: Not-in-operation
NOTE: For 2019, the percentages refer to the total reported events. Stack pull events identified in WAR are excluded.
SOURCE: U.S. DOT, BTS, SafeOCS program.

Table 24: Detection Methods for In-Operation Events (Surface Systems), 2017-19

	DETECTION METHOD	2017-18	2019
	Casual Observation	15.1%	11.4%
	Continuous Condition Monitoring	12.9%	6.8%
	On Demand	2.2%	0.0%
	Periodic Condition Monitoring	2.2%	0.0%
MIT	Periodic Maintenance	0.0%	6.8%
MIT	Inspection	6.5%	11.4%
MIT	Function Testing	9.7%	15.9%
MIT	Pressure Testing	51.6%	47.7%

KEY: In-operation
NOTE: For 2019, the percentages refer to the total reported events. Stack pull events identified in WAR are excluded.
SOURCE: U.S. DOT, BTS, SafeOCS program.

Root Causes

Table 25 and Table 26 show the distribution of root causes for the reported surface system events. As in past years, the root cause of wear and tear was reported for the highest percentage of events. Maintenance error was also a more common root cause for 2019 events, selected for 12 reported events, all of which occurred while not in operation. The root cause category of *other* was selected for 10 events (7 in-operation); for these events, the root cause was typically described as a primary contributing factor such as corrosion or debris.

Table 25: Root Causes of Not-in-Operation Events (Surface Systems), 2017-19

ROOT CAUSE	2017-18	2019
Design Issue	4.4%	0.0%
QA/QC Manufacturing	6.6%	4.7%
Maintenance Error	6.6%	27.9%
Procedural Error	3.3%	7.0%
Wear and Tear	37.4%	46.5%
Other	8.8%	7.0%
NOT DETERMINED		
Inconclusive	2.2%	2.3%
Assessment Pending	6.6%	0.0%
Not Reported*	24.2%	4.7%

KEY: Not-in-operation
NOTES:
* Most of the events without a reported root cause in 2017-18 occurred in 2017 and were reported via an early data collection form that did not request information on root causes.
\- For 2019, the percentages refer to the total reported events. Stack pull events identified in WAR are excluded.
SOURCE: U.S. DOT, BTS, SafeOCS program.

Table 26: Root Causes of In-Operation Events (Surface Systems), 2017-19

ROOT CAUSE	2017-18	2019
Design Issue	5.4%	4.5%
QA/QC Manufacturing	1.1%	6.8%
Maintenance Error	2.2%	0.0%
Wear and Tear	64.5%	50.0%
Other	2.2%	15.9%
NOT DETERMINED		
Inconclusive	0.0%	2.3%
Assessment Pending	6.5%	4.5%
Not Reported*	18.3%	15.9%

KEY: In-operation
NOTES:
* Most of the events without a reported root cause in 2017-18 occurred in 2017 and were reported via an early data collection form that did not request information on root causes.
\- For 2019, the percentages refer to the total reported events. Stack pull events identified in WAR are excluded.
SOURCE: U.S. DOT, BTS, SafeOCS program.

Stack Pulls

A subsea BOP stack pull is a very clear exercise of moving the stack from its subsea location on the wellhead back to the rig. The exercise of a surface BOP stack pull is less clear because, in some cases, it can occur without the physical removal of the stack from the wellhead. In general, a surface stack pull occurs when a component fails while in operation and must be repaired or replaced before operations can continue. More specifically, the SafeOCS WCE event reporting guidance defines a surface stack pull as: when a BOP component fails during operations and requires well conditioning and a mechanical barrier placement to make necessary repairs.[37] However, the data review indicates that some reported events that should have been reported as a stack pull were not because either well conditioning was not required or a mechanical barrier was not employed during the event. SafeOCS has identified this definition as an area for improvement.

Table 27: Types of Events Leading to Surface Stack Pulls, 2017-19

EVENT TYPE	2017-18	2019
LEAKS		
External Leak	2	7
Internal Leak	15	28
OTHER		
Communication / Signal Issue	-	1
Fail to Function on Command	2	-
Mechanical Issue	1	-
Process Issue	-	-
TOTAL	**20**	**36***

KEY: In-operation
NOTES:
* 2019 count includes 16 events identified in WAR (1 external leak and 15 internal leaks). Prior years do not include events identified in WAR.
- Dash indicates a count of zero.
SOURCE: U.S. DOT, BTS, SafeOCS program.

Table 27 shows that most reported surface stack pulls in 2019 were for internal leaks. These leaks were of consumable wellbore packers (see Table 32 in Appendix D), suggesting that, for some companies, they are not being replaced until they leak on a periodic test. Of the 28 stack pulls following internal leaks in 2019, 18 involved annular packing elements, discussed further under *Surface System Lessons Learned* (page 45).

A subsea BOP stack pull is a very clear exercise, while a surface BOP stack pull is not. Review of the data suggests that the surface stack pull definition is an area for improvement.

[37] A User Guide for Reporting Well Control Equipment Failure, U.S. Department of Transportation, Bureau of Transportation Statistics, Rev. 2.00 (Nov. 30, 2017), https://safeocs.gov/SafeOCSGuidanceRev2.pdf.

Root Causes of Surface Stack Pulls

Table 28 shows the distribution of root causes for events leading to surface stack pulls. Wear and tear was the most commonly reported root cause, reported for 10 surface stack pull events in 2019. For six events, excluding stack pull events identified in WAR, no definitive root cause was reported.

Stack Pull Combinations

Table 29 shows the components and event types for events leading to surface stack pulls in 2019. The similarities in the numbers of total in-operation events as compared to stack pulls for these components can be explained by typical surface system maintenance practices in which, due to the easy accessibility of equipment, components are typically not changed out until an issue occurs, even if that is during operations.

Table 28: Root Causes of Surface Stack Pulls, 2017-19

ROOT CAUSE	2017-18	2019
Design Issue	2	1
QA/QC Manufacturing	1	-
Maintenance Error	1	-
Wear and Tear	13	10
Other	-	3
NOT DETERMINED	-	-
Inconclusive	-	1
Assessment Pending	1	1
Not Reported	2	4
Unknown to SafeOCS*	-	16
TOTALS	**20**	**36****

KEY: In-operation
NOTES:
* Event identified in WAR data. The root causes of stack pull events identified in WAR are unknown to SafeOCS.
** 2019 count includes 16 events identified in WAR. Prior years do not include events identified in WAR.
- Dash indicates a count of zero.
SOURCE: U.S. DOT, BTS, SafeOCS program.

Table 29: Component Combinations Associated with Reported Surface Stack Pulls, 2019

ITEM	COMPONENT	EVENT TYPE	Total In-Op. Events	Stack Pulls
Annular Preventer	Operating System Seal	Internal Leak	3	3
	Packing Element	Internal Leak	19	18
BOP Control Panel	Central Control Console	Communication / Signal Issue	2	1
HPU Mix System	Regulator	External Leak	1	1
Pipe Ram Preventer	Bonnet Seal	External Leak	1	1
	Ram Block Seal	Internal Leak	2	2
Shear Ram Preventer	Bonnet Face Seal	External Leak	3	3
	Operating System Seals	Internal Leak	2	2
	Ram Block Seal	Internal Leak	3	3
Surface Control System	Regulator	External Leak	3	2
TOTALS			**39***	**36***

KEY: In-operation
NOTE: *Includes 16 stack pull events identified in WAR.
SOURCE: U.S. DOT, BTS, SafeOCS program.

Summaries of the 2019 surface stack pull events can be found in Appendix D.

Investigation and Analysis

I&A information was received for 21 of 87 surface system events.[38] Of the 13 I&As pertaining to these events (one investigation can involve multiple events), two were at the RCFA level, nine were at the SME review level, and the remainder were for events with immediately known causes. Table 30 summarizes the findings for I&As that included preventive actions pertaining to six events, grouped according to the component issue.[39] For surface WCE systems, components requiring further I&A for root cause determination are often sent to shore for evaluation by the OEM or equipment owner. Breaks in the communication chain could contribute to the relatively low number of events with submitted I&A information.

Table 30: Findings from I&As for Surface System Events, 2019

	ROOT CAUSE	ROOT CAUSE DETAILS	RECOMMENDED FOLLOW-UP ACTION
1	Design Issue	Piping design and the lack of a surge accumulator bottle was the reported cause of an annular regulator leaking internally on multiple occasions, with water hammer effect observed. As discussed further under Lessons Learned, however, reviewing these events together suggests that leaky annular operating system seals may have led to the regulator component failures.	Regulator OEM suggested that equipment owner redesign the control system by adding accumulator and plug off extra ports. OEM also recommended equipment owner consider changing control fluid. As discussed further under Lessons Learned, however, these reported follow-up actions may not be adequate in consideration of the final RCFA that included annular operating components.
2	QA/QC Manufacturing	While completing daily inspection, found two bolt heads from accumulator rack sheared. Investigation determined that the F593U fasteners are more susceptible to hydrogen induce corrosion, even when installed far above a splash zone.	OEM replaced ASTM F593U fasteners with 17-4-PH HT1150 grade stainless steel fasteners, which have similar mechanical properties and higher resistance to hydrogen induced corrosion.
3	Procedural Error	While replacing the annular packing element, the hydrostatic pressure from the fluid in the still attached hoses dislodged the adaptor ring and rolled the seal, though this was not noticed until the cap was removed after the annular body pressure test failed (due to visibility restrictions caused by the lifting frame).	Equipment owner to modify annular maintenance procedures to include disconnecting control hoses from SBOP (surface BOP) operator ports to prevent floating the adapter ring or piston. Equipment owner to carry out an engineering study to see if it is possible to modify the load ring to include inspection ports to allow subsea engineer to determine if bolted cap is properly seated on lower housing.

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

[38] The total includes one investigated event that also benefitted from the findings of another I&A for a similar issue.

[39] In the table, one row comprises one or more events and may reflect multiple I&As.

Surface System Lessons Learned

Leaking Annular Operating System Seals

In 2019, one rig's annular regulator was replaced four times in 70 days due to the regulator venting returns to the tank, followed by the replacement of the complete annular preventer. While the reported equipment failures were attributed to faulty regulators (see item 1 in Table 30), reviewing the events together suggests that leaky annular operating system seals may have led to the regulator component failures. These seals were worn, which may have allowed excess pressure to leak into the operating chamber when the wellbore pressure was higher than the regulated closing pressure. The excess pressure would have registered a higher than selected pressure on the regulator, causing the excess pressure to vent back to the tank.

For each of the first four events, the event investigations focused on failed regulator but were conducted in isolation (i.e., the events were investigated separately). These investigations were conducted onshore by a third-party service company in coordination with the operator (for two of the four events), the OEM of the pressure regulator (for one event), and the BOP control system OEM (for one event). For the fifth and final event, in which the annular BOP was replaced, the rig crew diagnosed BOP control fluid in the wellbore, showing that there was a leak between the operating system and the wellbore. Confirmation of the worn operating system seals on the annular BOP stump was made by the annular BOP OEM upon receipt of the BOP. The link between these events may not have been immediately evident because an I&A was performed onshore for each regulator failure as a standalone event. If a systemic RCFA were performed earlier, the subsequent regulator failures might have been prevented.

Failures of Annular Packing Elements

Most surface stack pulls in 2019 were due to the annular packing elements failing to hold pressure (i.e., some level of internal leak across the packing element). Each of these events was observed during a periodic 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.

CHAPTER 4: CONCLUSION AND NEXT STEPS

Key findings from this report include the following:

- For both subsea and surface WCE systems, event rates, adjusted based on the amount of rig activity, decreased from 2018 to 2019 and showed an overall decrease since 2017, driven by a decrease in event rate for subsea WCE systems. From 2018 to 2019, the event rate for subsea WCE systems decreased by 13.3 percent for in-operation events and 23.1 percent for not-in-operation events.
- Reporting of WCE events to SafeOCS appears to be incomplete, as some failure events identified in WAR data were not reported to SafeOCS. This apparent underreporting tended to be higher for surface system events, of which 67.7 percent of distinct not-in-operation events and 63.0 percent of distinct in-operation events were not reported to SafeOCS.
- Further separating not-in-operation from in-operation events in this report allowed for a clearer analysis of emerging trends and better year-to-year comparison. Not-in-operation events are often maintenance-related, while in-operation events are generally more significant in terms of risk and potential consequence. Of the total reported events for both subsea and surface systems, the largest percentage of events was reported for subsea systems while not in operation. This aligns with the rigorous MIT protocols carried out for these systems between well operations.
- Although both surface system rigs and subsea system rigs conducted well operations on a similar average number of wells per year, ten-fold fewer events were reported for surface systems than for subsea in 2019.
- Regarding the consequences of reported events, no reported event resulted in a loss of containment of wellbore fluids, and only one such event has been reported since 2017.

Next Steps: Opportunities for Improving Data Quality

SafeOCS continues to focus on improvement efforts in the following areas:

- Revise the data collection form and guidance to improve data quality. Specific form enhancements may include:
    - Improve the definition of a surface stack pull, and clarify and standardize the definitions overall.
    - Consider improvements to capture time to failure or equipment usage information better.
    - Revise event type categories to improve consistency across component types.
    - Streamline detection method selections.
- Refine and improve WCE component population estimates, such as by considering component criticality and developing event rate measures using these estimates.
- Enhance analysis of failure events identified in WAR data.
- Improve sharing of learnings with operators and other stakeholders.
- Work with OEMs to improve the criteria for identifying accelerated failures.
- Identify strategies to increase the coverage of the dataset and reduce underreporting.

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.[40] 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 of the failure, 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.

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[40] 84 Fed. Reg. 21,908 (May 15, 2019).

(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 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: 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 that can 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 blowout can occur when the oil or gas formation pressure from the well is greater than the hydrostatic pressure of the drilling fluid above it.

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 diluted 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: An approximate measure of rig activity when an equipment event could have occurred. It equals the number of the days during which some or all the WCE components may have been available and in use.

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.

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

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

BOP 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 stack retrieval.

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

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

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.

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

In-Operation (Surface): 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.

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 (LOC): An external leak of wellbore fluids outside of the pressure containing equipment boundary.

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: Well operations including intervention, workover, temporary abandonment, and permanent abandonment.

Not-in-Operation (Subsea): 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 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): 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 U.S. OCS during the listed period.

Root Cause: The fundamental reason for a problem. The core issue leading to a situation where an intervention could reasonably be expected to change performance and prevent an undesirable outcome.

Shear Ram: A closing and sealing component in a ram blowout preventer that can shear certain tubulars in the wellbore.

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, tubings, 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 Subunits: 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. Commonly known as wells spud or spuds.

Wells with Activity: This includes any well with drilling or non-drilling activities in the referenced calendar year.

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

Detection Method Terms

Casual Observation: A term used to describe non-invasive maintenance. This could be a simple walk by the component or an instrument monitoring that 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 a measured continuous physical force (usually water) in either an operating chamber or underneath a ram or annular BOP to prove pressure integrity.

Appendix C: 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/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

EO: Equipment owner

EPA: Environmental Protection Agency

FOIA: Freedom of Information Act

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

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

MUX: Multiplexed Control System

NPDES: National Pollutant Discharge Elimination System

OCS: Outer Continental Shelf

OEM: Original equipment manufacturer

QA/QC: Quality assurance/quality control

RCFA: Root cause failure analysis

ROV: Remotely operated vehicle

SME: Subject matter expert

WAR: Well activity report (per 30 CFR 250.743)

WCE: Well control equipment

WCR: Well Control Rule

Appendix D: 2019 Stack Pull Event Summaries

Table 31: Subsea Stack Pull Summaries, 2019

SUBUNIT	ITEM	COMP.	EVENT TYPE	DESCRIPTION	DETECTION METHOD	ROOT CAUSE
BOP Controls	BOP Control Pod	Piping / Tubing	External Leak	BOP #2 was pulled due to an unidentified hydraulic leak that caused the pumps to cycle every hour and a half. On recovery of the BOP it was noted that the blue pod supply to the auxiliary pod 90-degree tubing fitting was leaking when the pod was selected. The fitting was found to be tight and jam nut made up but that the O-ring has failed.	Continuous Condition Monitoring	Assessment Pending
BOP Controls	BOP Control Pod	SPM Valve	External Leak	Leaking SPM function 80 on yellow pod. Troubleshot issue and determined it to be the 1-1/2" NC (normally closed) SPM blew out. The nut that holds the spool to the piston rod had backed off and is missing, and the upper Delrin seal has shattered, causing the leak.	Function Testing	Maintenance Error
BOP Controls	BOP Controls Stack Mounted	Hose	External Leak	Routine monitoring of the BOP system noted a high cycle rate on the HPU pumps. The ROV noted an external leak from a hose fitting from the accumulators to the outer gas bleed valve close side of the SPM valve on the failsafe assist manifold. BOP stack retrieved. Found the 90-degree fitting to be very loose.	Periodic Condition Monitoring	Wear and Tear
BOP Controls	BOP Controls Stack Mounted	Piping / Tubing	External Leak	A leak was identified via the ROV on the pipework downstream of the shuttle valve on the stack connector lock circuit. The BOP was recovered to surface and the stack (wellhead) connector - latch circuit was inspected. The leak was observed at the 1 inch x 1/2 inch JIC (joint industry council) adaptor which was discovered loose.	Continuous Condition Monitoring	Maintenance Error
BOP Stack	Annular Preventer	Packing Element	Internal Leak	Unable to achieve a 6,400-psi test against the upper annular. Pulled LMRP to replace packing element.	Pressure Testing	Wear and Tear
BOP Stack	Pipe Ram Preventer	Ram Block Seal	Internal Leak	Lower pipe ram failed to seal during subsea pressure test. Upon recovery noticed significant damage to the forward side packer, likely related to operator error (closed on tool joint).	Pressure Testing	Procedural Error
BOP Stack	Stack Choke and Kill System	Choke and Kill Valve	External Leak	Negative pressure test failed due to sea water ingress through the lower inner kill valve grease fitting due to a loose cap. Pulled stack for repair.	On Demand	Assessment Pending

SUBUNIT	ITEM	COMP.	EVENT TYPE	DESCRIPTION	DETECTION METHOD	ROOT CAUSE
BOP Stack	Stack Choke and Kill System	Flex-loop Hose	External Leak	During the pressure testing a steady pressure drop was observed. Dye was pumped down to the stack and pressure applied. Via the ROV, dye was seen coming from the termination/hose interface from both connections for both the choke and kill flex hoses on the LMRP. Stack was pulled to surface.	Pressure Testing	Assessment Pending

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

Table 32: Surface Stack Pull Summaries, 2019

SUBUNIT	ITEM	COMP.	EVENT TYPE	DESCRIPTION	DETECTION METHOD	ROOT CAUSE
BOP Controls	BOP Control Panel	Central Control Console	Communication / Signal	Pressure fluctuation on manifold regulator was minimal at first and progressively got worse. Barksdale valve was leaking back to tank in open position. O-valve was replaced with spare.	Continuous Condition Monitoring	Wear and Tear
BOP Controls	HPU Mix System	Regulator	External Leak	During toolpusher's daily checks he noticed accumulator pump come on and run for about 6 seconds. Removed inspection cover and saw annular regulator leaking back into reservoir. Closed blind shear rams and screwed in manual locks. Replaced annular regulator with rebuilt regulator.	Inspection	Wear and Tear
BOP Controls	Surface Control System	Regulator	External Leak	Annular regulator was leaking back to tank. Tried to adjust annular pressure to see if this would stop the leak, to no luck. Installed spare and tested same with no leaks.	Function Testing	Inconclusive
BOP Controls	Surface Control System	Regulator	External Leak	Annular regulator was leaking back to tank. Adjusting annular pressure did not resolve leak. Had regulator hot shot to rig installed same. Installed and tested same with no leaks.	Function Testing	Design Issue
BOP Stack	Annular Preventer	Operating System Seal	Internal Leak	While testing BOPs, plastic found in the control valve open outlet physically preventing the valve from functioning. The plastic was identified, by the OEM, as part of an internal annular wear band. The entire annular BOP was removed and a replacement installed.	Inspection	Not Reported

SUBUNIT	ITEM	COMP.	EVENT TYPE	DESCRIPTION	DETECTION METHOD	ROOT CAUSE
BOP Stack	Annular Preventer	Operating System Seal	Internal Leak	Annular test pressure increased to 400 psi. Noticed pressure drop on accumulator, bled off pressure and open annular, BOP fluid was notice in wellbore. Pull test assembly, close and lock blind/shear rams. Nipple down annular and remove. Install new annular and nipple up. Test with 300 low pressure and 3500 high pressure.	Pressure Testing	Wear and Tear
BOP Stack	Annular Preventer	Operating System Seal	Internal Leak	While testing annular preventer on 2-7/8" pipe, test #12 pressured up to 300 psi good test, but attempt to go to 3,500 psi, leaked off at 80 psi/min. Replaced packing element and while testing discovered communication between wellbore and closing side of annular. Decision made to replace entire annular preventer.	Pressure Testing	Wear and Tear
BOP Stack	Annular Preventer	Packing Element	Internal Leak	During BOP pressure testing, it was identified that the annular was leaking wellbore pressure past the annular packing unit. The packing unit was replaced.	Pressure Testing	Not Reported
BOP Stack	Annular Preventer	Packing Element	Internal Leak	During routine biweekly testing, annular element failed to test on 3-1/2" drill pipe. It has tested on 5-7/8" drill pipe. Packing element was replaced and tested.	Pressure Testing	Wear and Tear
BOP Stack	Annular Preventer	Packing Element	Internal Leak	Upon completing 7" casing cementing operation that required the annular BOP to be closed for 9 hours, it was found that the wear bushing tool could not pass through the annular. Large amounts of rubber were protruding into the bore. A new element was installed and successfully tested.	Corrective Maintenance	Not Reported
BOP Stack	Annular Preventer	Packing Element	Internal Leak	While testing annular to 3,500 psi, noticed pressure bleeding off. Replaced packing element and successfully tested same. This element has been used for both drilling and non-drilling operations with a total of 63 closures.	Pressure Testing	Wear and Tear
BOP Stack	Annular Preventer	Packing Element	Internal Leak	Annular element would not test. Full replacement annular on board so decision made to replace entire unit.	Pressure Testing	Wear and Tear
BOP Stack	Annular Preventer	Packing Element	Internal Leak	Replaced entire annular preventer after packing element failed a test on 2-3/8" pipe.	Pressure Testing	Other
BOP Stack	Annular Preventer	Packing Element	Internal Leak	When testing the annular it leaked. Observed wear on the packing element and replaced same.	Pressure Testing	Wear and Tear

SUBUNIT	ITEM	COMP.	EVENT TYPE	DESCRIPTION	DETECTION METHOD	ROOT CAUSE
BOP Stack	Annular Preventer	Packing Element	Internal Leak	Changed out annular.	Pressure Testing	Unknown to SafeOCS*
BOP Stack	Annular Preventer	Packing Element	Internal Leak	Changed out annular packing element.	Pressure Testing	Unknown to SafeOCS*
BOP Stack	Annular Preventer	Packing Element	Internal Leak	Attempted to test annular on 3-1/2" pipe. Changed packing element.	Pressure Testing	Unknown to SafeOCS*
BOP Stack	Annular Preventer	Packing Element	Internal Leak	Replaced annular packing element.	Pressure Testing	Unknown to SafeOCS*
BOP Stack	Annular Preventer	Packing Element	Internal Leak	Suspended BOP testing and replaced annular packer.	Pressure Testing	Unknown to SafeOCS*
BOP Stack	Annular Preventer	Packing Element	Internal Leak	Replaced entire annular preventer after packing element failed a test on 2-3/8" pipe.	Pressure Testing	Unknown to SafeOCS*
BOP Stack	Annular Preventer	Packing Element	Internal Leak	Failed 3,500psi test. Changed packing element.	Pressure Testing	Unknown to SafeOCS*
BOP Stack	Annular Preventer	Packing Element	Internal Leak	Failed test on 2-7/8" pipe. Changed out annular packing element.	Pressure Testing	Unknown to SafeOCS*
BOP Stack	Annular Preventer	Packing Element	Internal Leak	Changed out annular.	Pressure Testing	Unknown to SafeOCS*
BOP Stack	Annular Preventer	Packing Element	Internal Leak	Annular failed pressure test on 3-1/2" pipe.	Pressure Testing	Unknown to SafeOCS*
BOP Stack	Annular Preventer	Packing Element	Internal Leak	Annular failed pressure test on 2-7/8" pipe, after functioning several times.	Pressure Testing	Unknown to SafeOCS*
BOP Stack	Pipe Ram Preventer	Bonnet Seal	External Leak	Began testing BOPs. Failed due to leak from bonnet seal. Repaired and continued.	Pressure Testing	Unknown to SafeOCS*
BOP Stack	Pipe Ram Preventer	Ram Block Seal	Internal Leak	When testing, the top pipe rams leaked. Upon inspection, wear on the ram packer was observed preventing seal around the drill pipe.	Pressure Testing	Wear and Tear

SUBUNIT	ITEM	COMP.	EVENT TYPE	DESCRIPTION	DETECTION METHOD	ROOT CAUSE
BOP Stack	Pipe Ram Preventer	Ram Block Seal	Internal Leak	While testing rams on 3-1/2" drill pipe, rams failed to test. Replaced face seals.	Pressure Testing	Wear and Tear
BOP Stack	Shear Ram Preventer	Bonnet Face Seal	External Leak	While performing a casing pressure test to 6,000 psi, the NE shear ram bonnet door seal failed.	Pressure Testing	Not Reported
BOP Stack	Shear Ram Preventer	Bonnet Face Seal	External Leak	While pressure testing BOPs, the forward BSR bonnet seal was seen to leak. An RTTS (retrievable squeeze tool) was installed to allow the bonnet to be opened and the seal replaced. The opposite seal was also replaced, but had not leaked. The BOPs were successfully tested.	Pressure Testing	Other
BOP Stack	Shear Ram Preventer	Bonnet Face Seal	External Leak	Leak from bonnet seal area of BSR. Shut down testing. Run and set RTTS. Found damage to bonnet sealing face. Decision made to replace complete double BOP. The double was sent for evaluation and repair. The report noted a severe gash in the sealing area of the bonnet gasket face on the lower double. The gash was most likely caused from a misalignment of the BOP ram when being closed after a bonnet gasket replacement.	Pressure Testing	Other
BOP Stack	Shear Ram Preventer	Operating System Seals	Internal Leak	3 bonnets failed operator tests and were replaced.	Pressure Testing	Unknown to SafeOCS*
BOP Stack	Shear Ram Preventer	Operating System Seals	Internal Leak	Removed bonnet, but unable to install replacement. Changed entire double ram BOP.	Pressure Testing	Unknown to SafeOCS*
BOP Stack	Shear Ram Preventer	Ram Block Seal	Internal Leak	When running drill pipe found a shear ram packer seal in the bailer. Inspected BOPs, replaced ram blocks and seals. Tested OK. Old rams sent to OEM for inspection.	Pressure Testing	Assessment Pending
BOP Stack	Shear Ram Preventer	Ram Block Seal	Internal Leak	Blind ram leaked at 5,000 psi. Replaced seals.	Pressure Testing	Unknown to SafeOCS*
BOP Stack	Shear Ram Preventer	Ram Block Seal	Internal Leak	Observed rubber object protruding out of annular preventer cavity above the UPR (upper pipe ram). Broke bonnet seals on BSR to replace rubber goods. Opened all bonnets to replace rubber goods, and changed annular packing element.	Pressure Testing	Unknown to SafeOCS*

NOTE: *Event identified in WAR data. The root causes of stack pull events identified in WAR are unknown to SafeOCS.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

APPENDIX E: ESTIMATED WCE SYSTEM COMPONENT COUNTS

The component count may provide insight into how often events occur relative to the number of similar components in use. However, it is important to consider that component counts vary, not only by the type of rig and the WCE system configuration, but by make, model, and generation. SafeOCS has developed estimates of the number of components for a "baseline" subsea WCE system with one or two subsea BOP stacks, as well as a "baseline" surface WCE system. For subsea systems, these estimates include the number of BOP stacks on each rig and the estimated riser joints in use on a subsea well of average water depth (5,200 ft.) in the GOM.

Table 33: Number of Components Per Rig

SUBUNIT	TYPE OF WCE SYSTEM		
	SUBSEA		SURFACE
	1 Stack	2 Stacks	1 Stack
Auxiliary Equipment	40	42	34
BOP Control Systems	1,390	2,497	143
BOP Stack System	380	760	141
Choke Manifold System	383	383	383
Diverter System	108	108	107
Riser System	788	788	0
TOTAL	3,089	4,578	808
	1 :	1.48	

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

Table 33 shows the estimated number of components for these baseline WCE systems broken down by subunit. This estimate was developed by subject matter experts and considered previous estimations by BSEE and the IOGP/IADC BOP Reliability JIP.[41] Complete listings of the components considered in developing the estimates are provided in Table 34 for subsea WCE systems and Table 35 for surface WCE systems. Parts (e.g., fasteners) were distinguished from components and excluded due to difficulty in quantifying and their potential to mask or hinder identifying patterns and trends. Similarly, the multitudes of hoses and tubing runs are generally counted as one component for each item, rather than quantified, because of wide variance across WCE systems and the potential to skew the data due to overcounting. Even though these parts are not counted as individual components, any events attributed to them are still reported.

[41] International Association of Oil & Gas Producers (IOGP) / International Association of Drilling Contractors (IADC) BOP Reliability Joint Industry Project (JIP). The JIP developed and manages RAPID-53, the Reliability and Performance Information Database for Well Control Equipment covered under API Standard 53.

It is often not possible to know when an event occurred if discovered during the maintenance, inspection, and testing being carried out on the standby BOP stack while the active BOP stack is on the well. Events may have occurred on the previous well but not discovered at the time, during the BOP stack recovery, or during pre-inspection function testing. The intent of the component population analysis is to place more emphasis on what fails and how, rather than when.

Measures SafeOCS is evaluating that use component count include:

- WCE subunit components: The total number of components associated with each WCE subunit (auxiliary equipment, BOP stack system, BOP control system, choke manifold system, diverter system, and riser system) for rigs with well operations during the period of interest.
- WCE total components: The total number of components for rigs with well operations during the period of interest where the estimated components for each rig's WCE subunits are summed to obtain the total WCE components.

Importantly, these measures cannot be thought of as equipment reliability rates. There are not many original equipment manufacturers of WCE equipment, but they each have their own specific designs for the same type of component. Another difficulty with gathering reliability data is that many of the components in use today span as many as seven revision levels of the same brand and model.

Subsea WCE System Component Counts

Table 34 shows the estimated numbers of components in a baseline subsea BOP system with one or two BOP stacks. The population headings have been matched to the data collection form and adjusted to include the riser components required for the 5,200-foot average water depth of a GOM subsea well.

Table 34: Listing of Subsea WCE System Component Counts

# BOP Stacks	1	2	1	2	1	2	1	2
Grand Total							3,089	4,578
Auxiliary Equipment					40	42		
Drill String Valve			4	4				
Float Valve	1	1						
Kelly Valve	2	2						
Stabbing Valve	1	1						
Gas Separation Equipment			2	2				
Mud Gas Separator	1	1						
Poor Boy Degasser	1	1						
Test Equipment			31	33				
Cable	1	1						
Check Valve	2	2						
End Connection	2	2						
Hose	1	1						
Needle Valve	10	10						
Piping / Tubing	1	1						
Pressure Gauge	3	3						
Pressure Recorder	3	3						
Pump	2	2						
Relief Valve	2	2						
Ring Gasket	2	3						
Test Stump	2	3						
Top Drive			3	3				
Hose	1	1						
Inside BOP	1	1						
Swivel	1	1						
BOP Stack System					380	760		
Annular Preventers			8	16				
End Connection	2	4						
Fasteners	0	0						
Hardware	3	6						
Operating System Seal	1	2						
Packing Element	1	2						
Ring Gasket	1	2						

# BOP Stacks	1	2	1	2	1	2	1	2
Ram BOP Body			24	48				
End Connection	4	8						
Fasteners	0	0						
Ram Cavity	6	12						
Ring Gaskets	2	4						
Side Outlets	12	24						
Lower Flex Joint			6	12				
End Connection	2	4						
Fasteners	0	0						
Flex Element	1	2						
Hardware	2	4						
Ring Gasket	1	2						
Riser Mandrel			2	4				
Fasteners	0	0						
Hardware	1	2						
Ring Gasket	1	2						
Pipe Ram Preventers			56	112				
Bonnet Face Seal	8	16						
Hardware	24	48						
Locking Device	4	8						
Operating System Seal	8	16						
Ram Block Hardware	4	8						
Ram Block Seal	8	16						
Riser Adaptor			11	22				
End Connection	1	2						
Fasteners	0	0						
Kick-out Sub	5	10						
Mud Boost Valve	1	2						
Ring Gasket	3	6						
Riser Coupling	1	2						
Riser Connector			56	112				
End Connection	2	4						
Fasteners	0	0						
Hardware	52	104						
Operating System Seal	1	2						
Ring Gasket	1	2						
Shear Ram Preventers			34	68				
Bonnet Face Seal	4	8						
Hardware	12	24						
Locking Device	4	8						
Operating System Seal	4	8						
Shear Ram Block Hardware	4	8						
Shear Ram Block Seal	6	12						
Stack Choke and Kill System			127	254				
Operating System Seal	14	28						

# BOP Stacks	1	2	1	2	1	2	1	2
C/K Spools	8	16						
C/K Valves	14	28						
C/K Receptacle	2	4						
C/K Stab	2	4						
End Connection	54	108						
Fasteners	0	0						
Flex Loop / Hose	2	4						
Hardware	2	4						
Hub Clamp	2	4						
Ring Gaskets	27	54						
Wellhead Connector			56	112				
End Connection	2	4						
Fasteners	0	0						
Hardware	52	104						
Operating System Seal	1	2						
Ring Gasket	1	2						
BOP Control System					1,390	2,497		
Control Panels			7	7				
Auxiliary Control Panel	0	0						
Central Control Console	1	1						
Driller's Control Panel	1	1						
Rig Manager Control Panel	0	0						
Software	1	1						
Subsea Control Panel	1	1						
Toolpusher's Control Panel	1	1						
Uninterruptible Power Supply (UPS)	2	2						
BOP Control Pod			681	1,348				
Accumulator	10	20						
Ball Valve	2	4						
Check Valve	4	8						
Compensated Chamber	2	4						
Control Valve	230	460						
Cylinder	4	8						
Electrical Connector	8	16						
Filter	8	16						
Flowmeter	2	4						
Inclinometer	2	4						
Interconnect Cable	4	8						
Interface Seal	18	36						
Metering Needle Valve	21	28						
Piping / Tubing	1	2						
Pod Hose	6	12						
Pod Stab	2	4						
Pressure Gauge	30	60						
Pressure Transducer	30	60						

	# BOP Stacks	1	2	1	2	1	2	1	2
	Primary Gripper	2	4						
	Regulator	14	28						
	Relief valve	5	10						
	Secondary Gripper	2	4						
	Shuttle Valve	10	20						
	Software	2	4						
	Solenoid Valve	258	516						
	Subsea Electronic Assembly Module	4	8						
Stack Mounted Controls				194	388				
	Accumulator	8	16						
	Cable	8	16						
	Check Valve	4	8						
	Conduit Manifold	2	4						
	Control Valve	12	24						
	Electrical Connector	16	32						
	Flowmeter	2	4						
	Hose	1	2						
	Hot Line Manifold	2	4						
	Hydraulic Stab	2	4						
	Inclinometer	1	2						
	Metering Needle Valve	4	8						
	Pilot Operated Check Valve	2	4						
	Piping / Tubing	1	2						
	Pod Receptacle	2	4						
	Pressure Gauge	0	0						
	Pressure Transducer	0	0						
	P / T Sensor	2	4						
	Quick Dump Valve	4	8						
	Regulator	1	2						
	Relief Valve	1	2						
	Riser Control Box (RCB)	1	2						
	Shuttle Valve	117	234						
	Wet Mate Connector	1	2						
Hydraulic Power Unit (HPU) / Mix System				217	217				
	Accumulator	82	82						
	Ball Valve	38	38						
	Check Valve	14	14						
	Control Valve	8	8						
	Filter	4	4						
	Flowmeter	2	2						
	Fluid	1	1						
	Fluid Recovery Unit	0	0						
	Gate Valve	3	3						
	Hose	1	1						
	HPU Control Panel	1	1						

# BOP Stacks	1	2	1	2	1	2	1	2
Instrumentation	0	0						
Mix System	1	1						
Metering Needle Valve	4	4						
Piping / Tubing	1	1						
Plug Valve	0	0						
Pressure Gauge	20	20						
Pressure Switch	12	12						
Pressure Transducer	4	4						
Pump	3	3						
Regulator	2	2						
Relief Valve	5	5						
Selector/Manipulator Valve	0	0						
Shuttle Valve	0	0						
Solenoid Valve	0	0						
Solenoid Valve (Pneumatic)	11	11						
Reels, Hoses, Cables			19	19				
Hot-line Hose	1	1						
HP Swivel	1	1						
Junction Box	2	2						
Multiplex (MUX) Cable	2	2						
MUX Cable Connector	2	2						
RBQ Hydraulic Junction Plate	0	0						
Reel	3	3						
Sheave	6	6						
Slip Ring	2	2						
Umbilical Hose	0	0						
Secondary - Acoustic System			102	182				
Accumulator	22	22						
Battery	1	2						
Check Valve	3	6						
Compensated Chamber	1	2						
Compensator	1	2						
Control Valve	9	18						
Filter	4	8						
Hose	1	2						
Hydraulic Stab	1	2						
Interface Seal	5	10						
Metering Needle Valve	1	2						
Pilot Operated Check Valve	8	16						
Piping / Tubing	1	2						
Pressure Gauge	2	4						
Pressure Transducer	9	18						
Regulator	1	2						
Relief Valve	2	4						
Shuttle Valve	12	24						

# BOP Stacks	1	2	1	2	1	2	1	2
Software	1	2						
Solenoid Valve	8	16						
Surface Control Unit (SCU)	1	2						
Transducer	2	4						
Transducer Deployment Arms	2	4						
Transponder	2	4						
Trigger Valve	1	2						
Wet Mate Connector	1	2						
Secondary - (ROV) Intervention			31	60				
Accumulator	1	2						
Hose	1	2						
Piping / Tubing	1	2						
Pressure Gauge	3	6						
Regulator	2	4						
ROV Receptacle	11	22						
ROV Stinger / Hot Stab	2	2						
ROV Valve	10	20						
Emergency - Autoshear / Deadman (EHBS)			138	275				
Accumulator	71	142						
Battery	1	2						
Check Valve	5	10						
Control Valve	15	30						
Cylinder	0	0						
Hose	1	2						
Hydraulic Stab	1	2						
Metering Needle Valve	1	2						
Pilot Operated Check Valve	11	22						
Piping / Tubing	1	1						
Pressure Gauge	1	2						
Pressure Transducer	8	16						
Regulator	1	2						
Relief Valve	4	8						
Shuttle Valve	5	10						
Solenoid Valve	10	20						
Timing Circuit	1	2						
Trigger Valve	1	2						
Emergency - EDS			1	1				
Software	1	1						
Choke Manifold System					383	383		
Auto-Choke			8	8				
Actuator	1	1						
End Connection	2	2						
Fasteners	0	0						
Hardware	5	5						
Choke / Kill Drape Hose			6	6				

# BOP Stacks	1	2	1	2	1	2	1	2
Choke Hose	1	1						
HP Swivel	2	2						
Hub Clamp	2	2						
Kill Hose	1	1						
Choke / Kill Piping Components			24	24				
Block	14	14						
Fasteners	0	0						
Fluid Cushion	4	4						
Spools	4	4						
Vessel Piping	2	2						
Choke Manifold Controls			11	11				
Accumulator	2	2						
Cable	1	1						
Control Valve	5	5						
HPU	1	1						
Hose	1	1						
Piping / Tubing	1	1						
Instruments			14	14				
Pressure Gauge	6	6						
Pressure Transducer	8	8						
Gate Valves			312	312				
End Connection	104	104						
Fasteners	0	0						
Hardware	203	203						
Actuator	5	5						
Manual Choke			8	8				
End Connection	2	2						
Fasteners	0	0						
Hardware	5	5						
Actuator	1	1						
Diverter System					108	108		
Diverter Assembly			13	13				
Flowline Seal	2	2						
Hose	1	1						
Hydraulic Control Interface	1	1						
Insert Packer	1	1						
Locking Dog	4	4						
Operating System Seal	1	1						
Packing Element	1	1						
Piping / Tubing	1	1						
Ring Gasket	1	1						
Fasteners	0	0						
Diverter Control System			39	39				
Accumulator	6	6						
Ball Valve	6	6						

# BOP Stacks	1	2	1	2	1	2	1	2
Check Valve	2	2						
Pressure Gauge	6	6						
Pressure Switch	6	6						
Pump	0	0						
Regulator	5	5						
Relief Valve	2	2						
Selector / Manipulator Valve	6	6						
Handling Tool			2	2				
Hardware	2	2						
Housing			6	6				
Dog	4	4						
Fasteners	0	0						
Hose	1	1						
Piping / Tubing	1	1						
Diverter Piping			31	31				
End Connection	20	20						
Fasteners	0	0						
Gaskets	10	10						
Pipe	1	1						
Diverter Valve			12	12				
Actuator	5	5						
Valve	5	5						
Hose	0	0						
Instrumentation	1	1						
Piping / Tubing	1	1						
Upper Flexjoint			5	5				
End Connection	2	2						
Fasteners	0	0						
Flex Element	1	1						
Hardware	1	1						
Ring Gasket	1	1						
Riser System (for the average GOM water depth of 5,200 feet)					788	788		
Handling Tool			3	3				
Hydraulic Tool	2	2						
Manual Tool	1	1						
Riser Joints			731	731				
BLAT (BOP Landing Assist Tool)	1	1						
Buoyancy	278	278						
Choke and Kill Line	116	116						
Conduit Line	116	116						
Fasteners	0	0						
Riser Bolt	0	0						
Lift Tool	1	1						
Main Tube	58	58						
Mud Boost Line	58	58						

# BOP Stacks	1	2	1	2	1	2	1	2
Other Line	0	0						
Riser Coupling	58	58						
Riser Protection	44	44						
Shuttle Tool	1	1						
Telescopic Joint			25	25				
Bearing	1	1						
Choke / Kill Line	2	2						
Fasteners	0	0						
Gooseneck	5	5						
HFGS	0	0						
Hose	1	1						
HP Swivel	1	1						
Hub Clamp	3	3						
Hydraulic Stab	2	2						
Inner Barrel	1	1						
Inner Barrel Lock	1	1						
Mud Boost Drape Hose	1	1						
Mud Boost Line	1	1						
Other Line	2	2						
Packer	2	2						
Piping Tubing	1	1						
Vessel Piping	1	1						
Tension Ring			16	16				
Bearing	1	1						
Fasteners	0	0						
Hardware	15	15						
Riser Gas Handling Equipment			13	13				
Ball Valve	2	2						
C / K Line	2	2						
Fasteners	0	0						
Gooseneck	2	2						
Hose	2	2						
Mud Boost Line	1	1						
Other Line	2	2						
Packer	1	1						
Piping / Tubing	1	1						

KEY:

Grand Total

Subunit

Item

Component

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

Surface WCE System Component Counts

Table 35 shows the estimated numbers of components in a baseline surface BOP system. The population headings have been matched to the data collection form.

Table 35: Listing of Surface WCE System Component Counts

Grand Total					808
	Auxiliary Equipment			34	
		Drillstring Valve	4		
		Float Valve	1		
		Kelly Valve	2		
		Stabbing Valve	1		
		Gas Separation Equipment	2		
		Mud Gas Separator	1		
		Poor Boy Degasser	1		
		Test Equipment	25		
		Cable	1		
		Check Valve	2		
		End Connection	2		
		Hose	1		
		Needle Valve	10		
		Piping / Tubing	1		
		Pressure Gauge	2		
		Pressure Recorder	2		
		Pump	1		
		Relief Valve	1		
		Ring Gasket	1		
		Test Stump	1		
		Top Drive	3		
		Hose	1		
		Inside BOP	1		
		Swivel	1		
	BOP Stack System			141	
		Annular Preventers	8		
		End Connection	2		
		Fasteners	0		
		Hardware	3		
		Operating System Seal	1		
		Packing Element	1		
		Ring Gasket	1		
		Ram BOP Body	24		
		End Connection	4		
		Fasteners	0		
		Ram Cavity	6		

Ring Gaskets	2		
Side Outlets	12		
Pipe Ram Preventers		48	
Bonnet Face Seal	6		
Hardware	18		
Locking Device	6		
Operating System Seal	6		
Ram Block Hardware	6		
Ram Block Seal	6		
Shear Ram Preventers		17	
Bonnet Face Seal	2		
Hardware	6		
Locking Device	2		
Operating System Seal	2		
Shear Ram Block Hardware	2		
Shear Ram Block Seal	3		
Stack Choke and Kill System		44	
Operating System Seal	4		
C / K Spools	4		
C / K Valves	4		
End Connection	16		
Fasteners	0		
Flex Loop / Hose	2		
Hub Clamp	2		
Ring Gaskets	12		
BOP Control System			143
Control Panels		5	
Auxiliary Control Panel	0		
Central Control Console	0		
Driller's Control Panel	1		
Rig Manager Control Panel	0		
Software	1		
Subsea Control Panel	0		
Toolpusher's Control Panel	1		
Uninterruptible Power Supply (UPS)	2		
Stack Mounted Controls		4	
Hose	1		
Piping / Tubing	1		
P / T Sensor	2		
Hydraulic Power Unit (HPU)		134	
Accumulator	40		
Ball Valve	19		
Check Valve	8		
Control Valve	8		
Filter	4		
Flowmeter	1		

		Fluid	1
		Gate Valve	3
		Hose	1
		HPU Control Panel	1
		Instrumentation	0
		Piping / Tubing	1
		Plug Valve	0
		Pressure Gauge	10
		Pressure Switch	12
		Pressure Transducer	4
		Pump	3
		Regulator	2
		Relief Valve	5
		Selector/Manipulator Valve	0
		Shuttle Valve	0
		Solenoid Valve	0
		Solenoid Valve (Pneumatic)	11
Choke Manifold System			383
	Auto-Choke		8
		Actuator	1
		End Connection	2
		Fasteners	0
		Hardware	5
	Choke / Kill Drape Hose		6
		Choke Hose	1
		HP Swivel	2
		Hub Clamp	2
		Kill Hose	1
	Choke / Kill Piping Components		24
		Block	14
		Fasteners	0
		Fluid Cushion	4
		Spools	4
		Vessel Piping	2
	Choke Manifold Controls		11
		Accumulator	2
		Cable	1
		Control Valve	5
		HPU	1
		Hose	1
		Piping / Tubing	1
	Instruments		14
		Pressure Gauge	6
		Pressure Transducer	8
	Gate Valves		312
		End Connection	104

Fasteners	0		
Hardware	203		
Actuator	5		
Manual Choke		8	
End Connection	2		
Fasteners	0		
Hardware	5		
Actuator	1		
Diverter System			107
Diverter Assembly		13	
Flowline Seal	2		
Hose	1		
Hydraulic Control Interface	1		
Insert Packer	1		
Locking Dog	4		
Operating System Seal	1		
Packing Element	1		
Piping / Tubing	1		
Ring Gasket	1		
Fasteners	0		
Diverter Control System		39	
Accumulator	6		
Ball Valve	6		
Check Valve	2		
Pressure Gauge	6		
Pressure Switch	6		
Pump	0		
Regulator	5		
Relief Valve	2		
Selector / Manipulator Valve	6		
Handling Tool		2	
Hardware	2		
Housing		6	
Dog	4		
Fasteners	0		
Hose	1		
Piping / Tubing	1		
Diverter Piping		31	
End Connection	20		
Fasteners	0		
Gaskets	10		
Pipe	1		
Diverter Valve		12	
Actuator	5		
Valve	5		
Hose	0		

Instrumentation	1	
Piping / Tubing	1	
Diverter Spools		4
Spools	2	
Overshots	2	

KEY:

Grand Total
Subunit
Item
Component

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

APPENDIX F: SUBUNIT BOUNDARIES

This appendix provides descriptions of each of the WCE subunits: auxiliary equipment, BOP control systems (primary, secondary, and emergency), BOP stack system, choke manifold system, diverter system, and riser system. Example schematic drawings are included at the end of this appendix.

The Auxiliary Equipment

Per API Standard 53, the auxiliary equipment includes the components listed in Table 36. The table is annotated to describe the equipment and identify whether it applies to subsea or surface WCE systems.

Table 36: Auxiliary Equipment

COMPONENT		USE
Similar equipment used on both subsea and surface WCE systems		
1	Kelly valves	Valves used within the drill string.
2	Drill pipe safety valves	
3	Inside BOP	
4	Float valves	
5	Trip tank	Part of the mud (drilling fluid) flow.
6	Pit volume measurement and recording devices	
7	Flow rate sensor	
8	Poor boy degasser	Part of the mud flow, but specifically used for removing gas from the mud.
9	Mud gas separator	
10	Mechanical type degasser	
11	Flare/vent lines	
12	Standpipe choke	
13	Top drive equipment	Mechanism that rotates the drill pipe when directing mud down the drill string.
Equipment specific to subsea WCE systems		
14	Guide frames	Part of the subsea stack framework.
15	Slope indicators	
16	Pin connector / hydraulic latch	No longer in common use, but formerly used on a well where shallow gas was expected, to guide the gas to the rig instead of aerating the water and reducing the buoyancy below the rig.

17	Mud booster line	One of the riser auxiliary lines that allows additional mud to be pumped into the riser at the top of the BOP stack to help lift the drill cuttings up the large bore of the riser main tube.
18	Hydraulic supply line	Auxiliary lines on the riser used to carry the water-based BOP control fluid from the surface accumulators down to the subsea BOP stack.
19	Riser tensioning support ring	Remotely latched mechanism used to attach the hydro-pneumatic riser tensioners to the drilling riser.

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

The Subsea BOP Control System

Per API Standard 53, subsea BOP control systems must have the following, unless otherwise noted: redundant control pods, an autoshear emergency control system, a deadman emergency control system, an ROV intervention secondary control system, an acoustic secondary control system (optional for all subsea systems), and an emergency disconnect sequence (EDS) (mandatory for all stacks run from a dynamically-positioned vessel but optional for moored vessels).

The API Standard 53 minimal requirements stated above do not specify the full range of equipment/components available and in use today. Not only do current systems allow for full control from various panels, but they also provide readbacks in the form of position, inclination angles, flow meter readings, pressures, temperatures, alarms, and various system fault messages, both live and logged. Much of this information is also sent, through secure communications, to the shore bases for further monitoring or troubleshooting purposes.

The Primary BOP Control System

The primary BOP control system (example schematic shown in Figure A) includes all of the functions that can be operated or monitored from any one of multiple panels on the rig (e.g., the driller's control panel, toolpusher's control panel, or subsea maintenance panel). Each of these panels can operate all of the BOP stack functions. Any one of these panels can send a signal to the two identical control pods, each of which receives the signal but only the active pod responds to it. The other pod is fully redundant to the active pod and on standby for immediate use if required. These control pods, mounted on the LMRP, decode the multiplexed signals from the surface, and send the hydraulic fluid at the required pressure to the commanded function. The control pods each have independent MUX control cables from the surface panels. The BOP stack also has (at least) two independent hydraulic supplies, adding to the levels of redundancy throughout.

Even though the two control pods and multiple panels provide full redundancy of control to the BOP stack, there are some events that could prevent the rig personnel from affecting those controls. These include an inadvertent disconnect of the LMRP from the lower stack, the loss of the marine riser, or even the loss of the rig itself. In anticipation of one of these incidents occurring, the subsea BOP stacks are outfitted with additional control equipment.

The BOP Emergency Control System

The emergency control system, shown in Figure B, includes the automated controls such as deadman and autoshear. These systems can command the functions necessary to seal the well automatically, independent of the primary control system components, if the power and signals to both pods are simultaneously lost (autoshear), or if the LMRP is disconnected, either deliberately or accidentally, from the lower BOP stack (deadman).

The Secondary BOP Control System

The secondary control system includes BOP stack framework-mounted interface control panels such that the remotely operated vehicle (ROV) can connect to the BOP stack to operate certain functions externally. The secondary control system, shown in Figure C, also includes an (optional[42]) acoustic control interface with a stand-alone control pod. This secondary control system allows for the operation of selected BOP stack functions via one of two redundant transponders that send and receive coded audio signals transmitted through the water from either the rig or a portable control unit.

Figure D shows a typical example of a control system arrangement for the shear rams. The shear rams in this example can be closed from seven different sources. This means that they

[42] Optional, in this case, refers only to the installation of the equipment. If an acoustic control system is installed and mentioned on the permit to drill, then it is expected to be fully functional.

must be tested from seven different sources, and every function reduces the remaining life of the seals.

The Subsea BOP Stack

The subsea BOP stack, shown in Figure E, shall[43] provide a means to do the following:

- Close and seal on the drill pipe, tubing, casing, or liner and allow circulation.
- Close and seal on an open hole and allow volumetric well control operations.
- Strip the drill string.
- Hang-off the drill pipe on a ram BOP and control the wellbore.
- Shear the drill pipe, tubing, or wireline in use.
- Disconnect the riser from the BOP Stack. Circulate across the BOP stack to a choke manifold.

Subsea BOP stacks shall be class 5 (10,000 psi or greater maximum anticipated wellhead pressure (MAWHP))[44] or greater with:

- Minimum of one annular preventer
- Minimum of two pipe rams
- A minimum of two sets of shear rams, one of which must be able to seal. (Moored rigs can have only one set of shear rams after conducting a risk assessment.)

Subsea BOP stack mounted choke and kill lines provide redundancy as well as multiple access points to the BOP stack and allow for well control operations as follows:

- Circulating down one line and up the other line.
- Circulating down the drill pipe and up either or both lines.

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[43] All shall statements in this section refer to API Standard 53 requirements.

[44] BOP stack classifications are per API Standard 53.

- Pumping down one or both lines.
- Allow well pressure monitoring.
- All outlets connected to the BOP stack shall have two valves, all of which are remote controlled.

The BOP stack includes the ram and annular BOPs, drilling spools, adaptor spools, and the side outlet valves. Additional components not explicitly mentioned in API Standard 53 are required for the system to work.

The Surface BOP Control System

The BOP control system for a surface stack, shown in Figure F, is usually a simple closed loop direct hydraulic system. The HPU pressurizes the hydraulic fluid from the reservoir tank, which it stores in the surface accumulator. The accumulator feeds a pressure regulator, which then directs the fluid to a control manifold. This manifold supplies the individual valves for each function which then direct the fluid directly to the BOPs and valves. When a function such as the annular is operated, the fluid on the close side of the annular is returned to the reservoir. Other than having two remote control panels to operate the manifold valves, there is essentially no redundancy. The surface shear ram has only one close supply line, but it is always accessible.

The Surface BOP Stack

The surface BOP Stack, shown in Figure G, shall[45] provide a means to do the following:

- Close and seal on the drill pipe, tubing, casing, or liner, and allow circulation.
- Close and seal on an open hole and allow volumetric well control operations.
- Strip the drill string.
- Shear the drill pipe or tubing when blind shear rams are installed.

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[45] All shall statements in this section refer to API Standard 53 requirements.

- Circulate across the BOP stack to a choke manifold.

BOP stacks are classed[46] according to pressure requirements from a class 2 BOP stack (which, for a maximum anticipated surface pressure (MASP) of 3,000 psi, would include one blind ram plus one pipe ram or one annular BOP) to a class 5 BOP Stack (which, for a MASP of 10,000 psi or greater, includes at least one annular, one BSR, and two pipe rams, and the fifth BOP can be either an annular or a ram).

Surface BOP stack choke and kill systems provide access points to the BOP stack and allow the following:

- Circulating down the kill line and up the choke line.
- Circulating down the drill pipe and up the choke line.
- Pump down the kill line.
- Allow well pressure monitoring.
- All outlets connected to the BOP stack shall have two valves, one of which must be remote controlled.

The Choke Manifold System

The choke manifold system, shown in Figure H, is an arrangement of piping, valves, chokes, and pressure sensors used to control pressurized fluids coming out of the well. The manifolds are designed to allow drilling or for wellbore fluids to be evacuated from the well and safely directed to the proper location. During a well kill operation, this could involve drawing heavy mud (drilling fluid) from the mud pits via the standpipe manifold and pumping it down the kill line. With a BOP closed, the gas-cut mud, or simply the lighter mud, is directed up the choke line and back to the manifold. When the fluid reaches the manifold, it is directed through a remotely adjustable choke designed to restrict the flow and thus control the pressure coming out of the well.

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[46] BOP stack classifications are per API Standard 53.

Typically, the valves and piping downstream of the chokes are rated for lower pressure than those on the upstream side. The lower pressure fluid can then be directed to the burner boom, overboard lines, mud-gas separator, or one of the trip tanks, as required. The mud-gas separator (MGS) is typically a large vertical vessel, fitted with internal baffles, used to remove undesired gas from drilling mud when it returns to surface while circulating the well. The mud enters the tank from the top and hits the baffles inside the tank separating the gas, which flows freely up the vent pipe from the mud, which is routed back to the mud tanks (pits) for reuse.

All choke manifolds have at least two chokes for redundancy purposes. If the choke becomes blocked during a well kill operation, it is relatively easy to redirect the flow through the (an) alternate choke with minimal disruption. The functional requirements for the choke manifold are essentially the same for both subsea and (≥10,000psi) surface systems. However, the surface systems are often less versatile in the possible routings through the manifold.

The Diverter System

The diverter equipment, shown in Figure I, is mounted underneath the rig floor rotary table and, on a subsea system, provides the interface between the drilling riser and the drilling fluid (mud) systems. The components include the diverter housing, the diverter assembly, overboard and flowline valves, and pipework. A surface system does not have a riser per se; instead, they have several overshot spools to connect from the top of the annular to the diverter. The use and operation of the diverter systems are similar for both subsea and surface WCE systems.

Mud is pumped down the drill pipe to provide the primary well control in the form of hydrostatic pressure, to lubricate and cool the drill bit, and to carry cuttings back to the surface. In normal circumstances, the return flow travels up to the diverter housing, then through the flowline valve, down the flowline, and on to the mud treatment center, where it is cleaned and treated before being circulated back into the well.

In the event of a shallow gas kick or a blowout, the diverter packing unit would be closed to prevent the flow from reaching the rig floor. Activating the packer to the closed position automatically fires a sequence to close the flowline valve and to open the overboard lines simultaneously to prevent a closed system because the diverter is, by definition, not a blowout preventer. Rather, it is a safety device intended to give the people on the drill floor vital minutes to evacuate in case of an emergency.

The Riser System

The marine drilling riser system includes all components from the top of the BOP stack to the bottom of the diverter. On a subsea system, this includes a quantity (string) of riser joints to suit the rig. A 12,000-foot capable rig that uses 75-foot joints will have 160 joints of riser, plus a set of “pup” joints which have similar specifications but are a mixture of shorter lengths to allow the correct overall measurements to be reached.

Figure J shows an example schematic for a riser joint. Each joint has a “pin” on one end and a “box” on the other. The pin end has male stabs for the main tube and all of the auxiliary lines. The box end is the female side of the connections and contains individual redundant seals for each line. The pin is stabbed into the box and then, depending on the style of riser there may be bolt, dogs, or a breech lock to join the joints together. The majority of deep water riser joints will be enclosed in buoyancy modules to reduce the “wet” weight of the riser and help to keep the riser string in-tension.

Above the riser joints is the telescopic joint. This is used how it sounds, a special joint of riser with a larger bore outer barrel at the bottom and an inner barrel at the top with two redundant sealing units in the middle. The outer barrel connects to the riser string, and the inner barrel connects to the diverter completing a sealed conduit from the BOP stack to the mud treatment equipment on the rig. The telescopic joint is required to accommodate the heaving action of the rig riding the tide and waves while in operation.

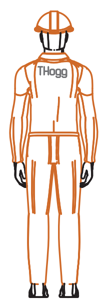
Pressure tests of the choke and kill lines are carried out during stack deployment; the choke and kill lines, which form a circuit between the BOP stack and the choke manifold, can only be tested when they are all properly connected. Because the complete circuit can involve passing through up to 12,000 feet of water, sections of these lines are attached to the marine riser joints which are each typically between 75 and 90 feet long. One of these riser joints connects directly to the top of the BOP stack and, when this has been lowered through the rig, additional joints are connected until the BOP stack reaches the wellhead. To reach the deepwater rig's maximum depth this could involve 160 x 75-foot joints of riser, with one line on each side, totaling 320 tests that could be required during this phase. It is, however, normal practice to only test the choke and kill lines after every tenth joint to reduce the overall time required. In addition to these pressure tests, the submerged electronic components of the BOP control system are scrutinized as the hydrostatic pressure affecting them increases with the depth (c. 5,350 psi at 12,000 feet).

Example Schematics

The following pages present example schematics referenced above.

- Figure A: Example Schematic for Subsea Primary Control System – Shear Ram
- Figure B: Example Schematic for Emergency Deadman/Autoshear System
- Figure C: Example Schematic for Secondary Acoustic Control System
- Figure D: Example Schematic for Subsea Shear Ram Control System Arrangement
- Figure E: Example Schematic for Subsea BOP Stack
- Figure F: Example Schematic for Surface BOP Stack Control System
- Figure G: Example Schematic for Surface BOP Stack
- Figure H: Example Schematic for Choke Manifold
- Figure I: Example Schematic for Diverter System
- Figure J: Example Schematic for Riser Joint

Example Schematic Drawings R1



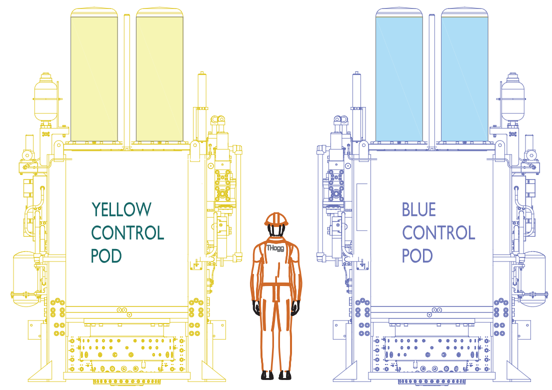
KEY TO DRAWING LAYERS

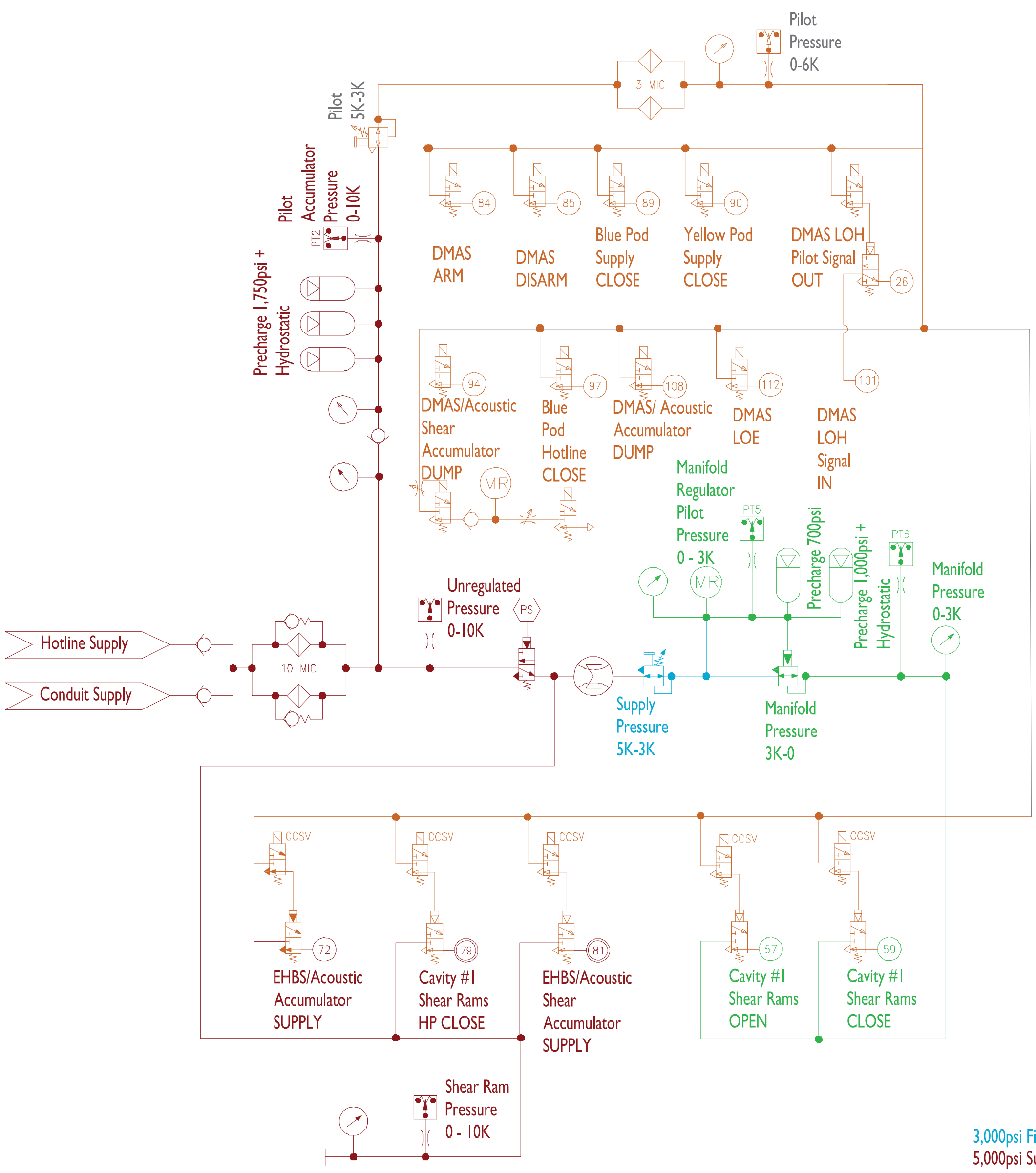
3,000psi Fixed Pressure	0,169,211
5,000psi Supply Pressure	140,0,0
Acoustic Control Pressure	46,49,146
Acoustic Regulated Pressure	178,210,53
Blue Pod	110,120,255
BOP Equipment	Multi-colored for cutaway clarity
Compensated Chamber	137,137,137
Choke Line	0,0,255
Diverter Assembly	180,80,180
Diverter Housing	80,80,80
Diverter Pipework	40,140,140
Diverter Spool	60,120,80
DMAS (Deadman/Autoshear)	165,145,155
Drill Pipe	50,50,50
Kill Line	255,0,0
Main Tube	0,31,127
Manifold Pressure	37,179,75
Mud Boost Line	0,255,0
Packing Element	130,130,0
Pilot Pressure	200,100,0
ROV	0,100,100
Upper Flex Joint	175,125,100
Vent	0,0,0
Yellow Pod	225,200,10

THogg

(SOURCE: US DOT, BTS, SafeOCS Program)

Figure A. Example Schematic for Subsea Primary Control System - Shear Rams





This schematic shows the typical hydraulic controls in one of the two redundant pods. used to control only one set of shear rams.

KEY TO DRAWING LAYERS

3,000psi Fixed Pressure	0,169,211
5,000psi Supply Pressure	140,0,0
Acoustic Control Pressure	46,49,146
Acoustic Regulated Pressure	178,210,53
Blue Pod	110,120,255
Manifold Pressure	37,179,75
Pilot Pressure	200,100,0
Yellow Pod	225,200,10

(SOURCE: US DOT, BTS, SafeOCS Program)

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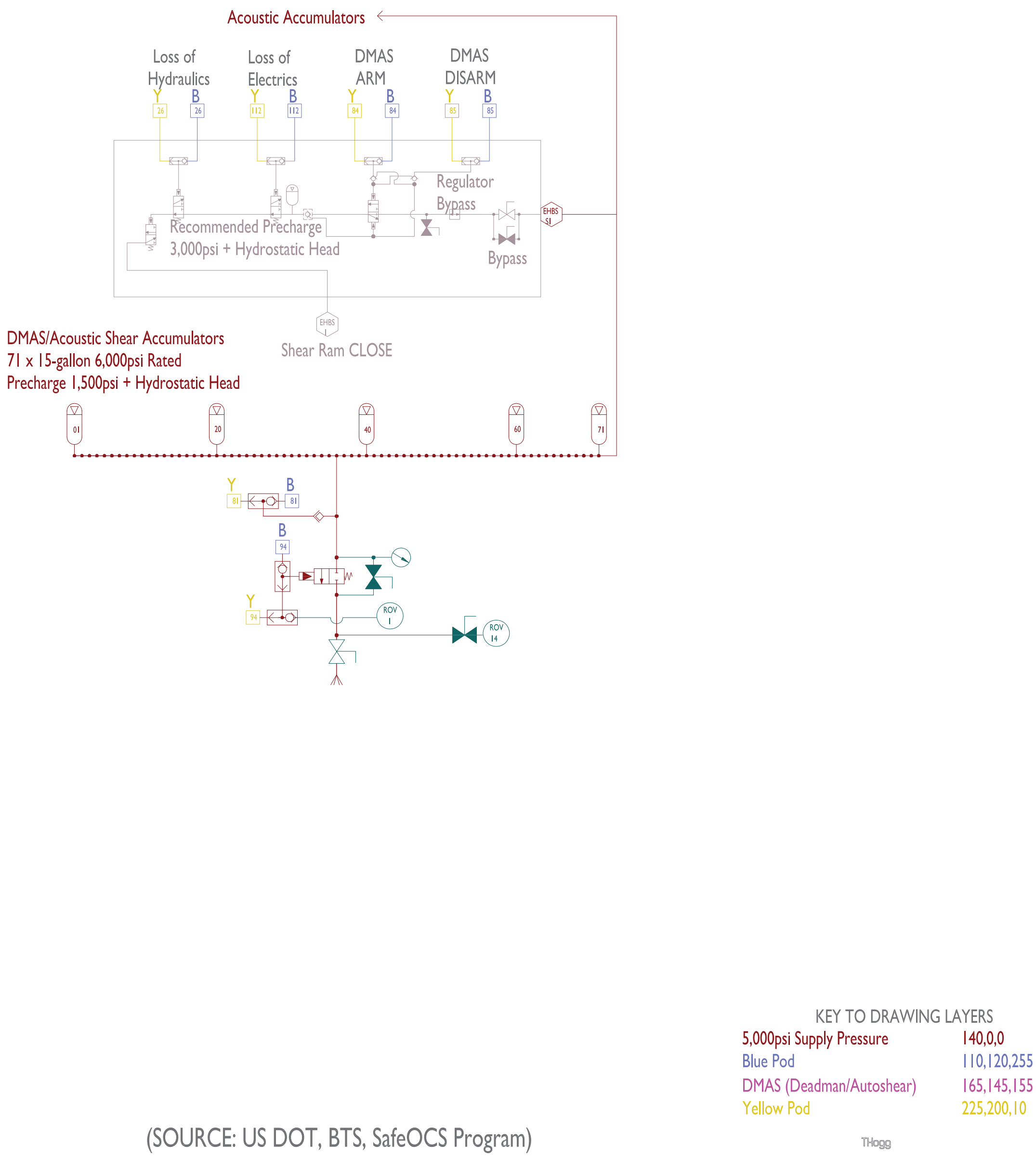
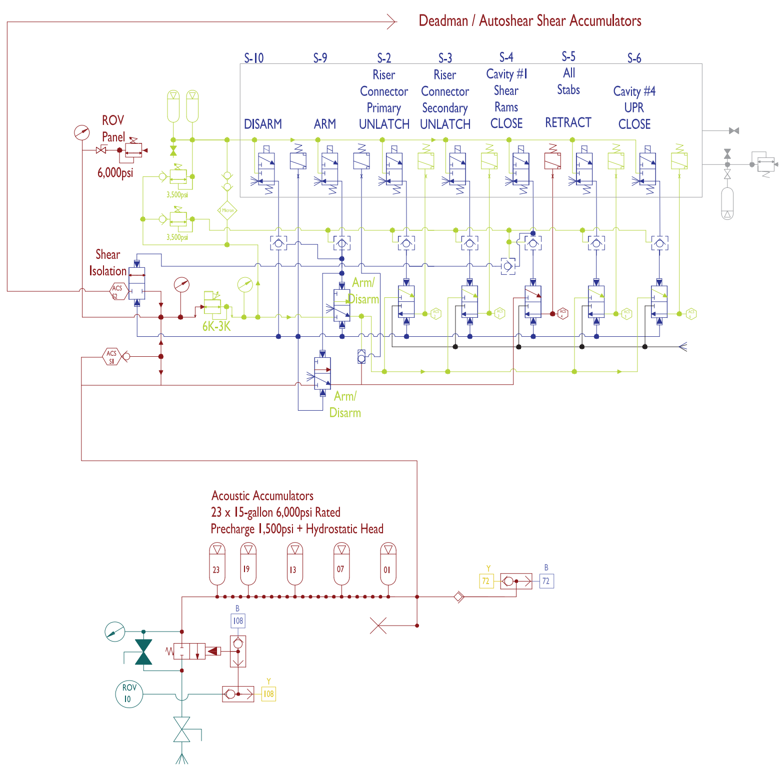
Figure B. Example Schematic for Emergency Deadman/Autoshear Control



(SOURCE: US DOT, BTS, SafeOCS Program)

Figure C. Example Schematic for Secondary Acoustic Control System



KEY TO DRAWING LAYERS

5,000psi Supply Pressure	140,0,0
Acoustic Control Pressure	46,49,146
Acoustic Regulated Pressure	178,210,53
Blue Pod	110,120,255
Compensated Chamber	137,137,137
ROV	0,100,100
Yellow Pod	225,200,10

(SOURCE: US DOT, BTS, SafeOCS Program)

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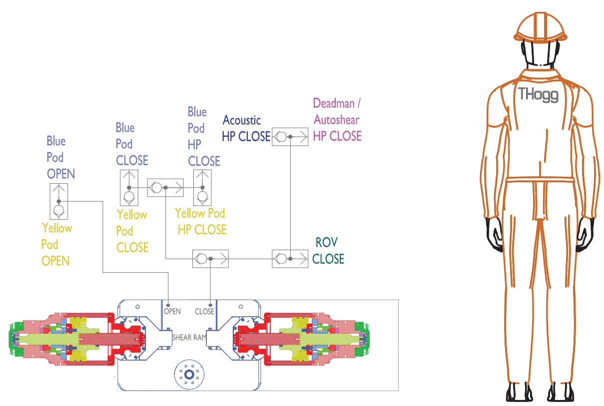
Figure D. Example Schematic for Subsea Shear Ram Control System Arrangement



KEY TO DRAWING LAYERS

Blue Pod	110,120,255
BOP Equipment	Multi-colored for cutaway clarity
DMAS (Deadman/Autoshear)	165,145,155
Yellow Pod	225,200,10

(SOURCE: US DOT, BTS, SafeOCS Program)

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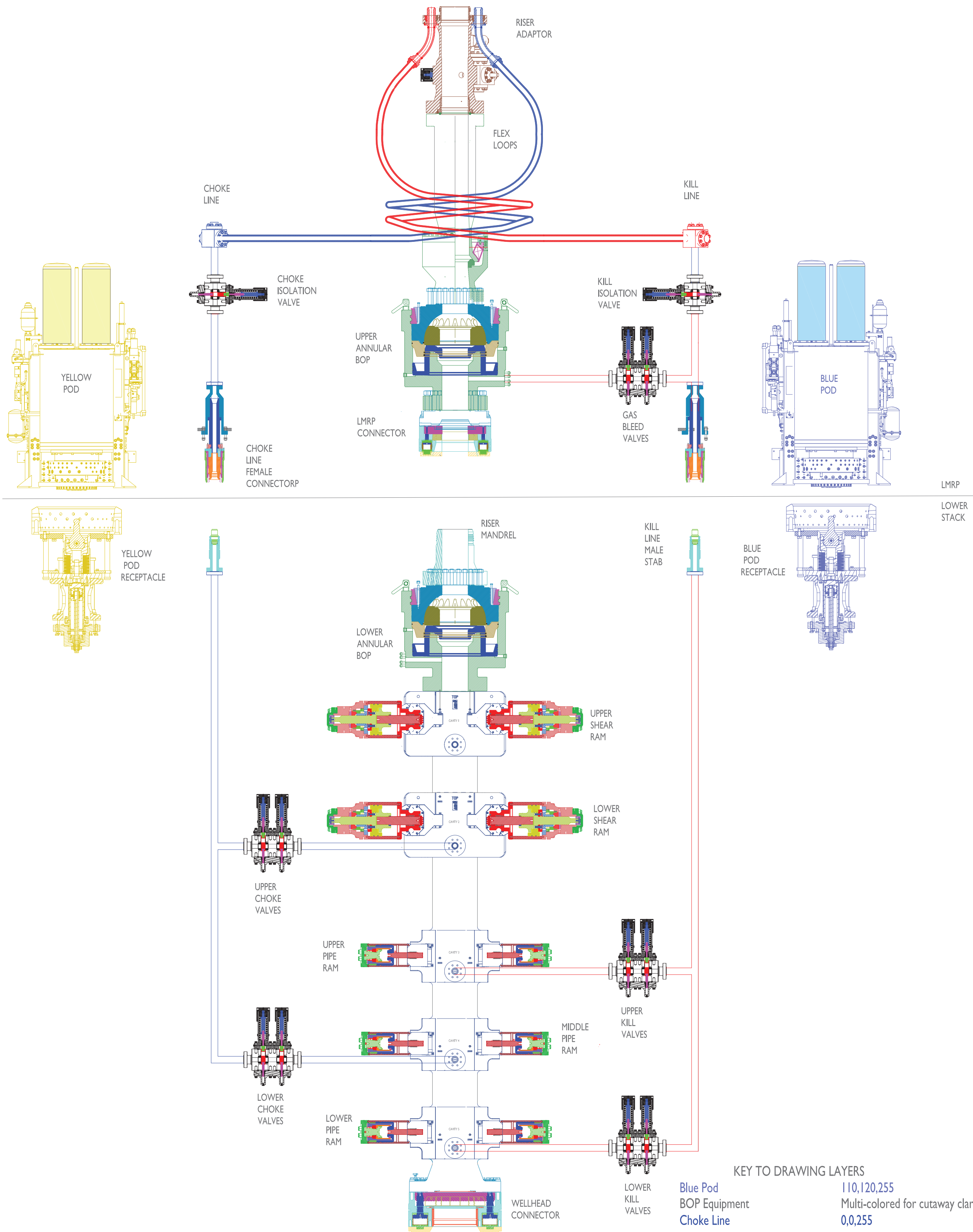
Figure E. Example Schematic for Subsea BOP Stack

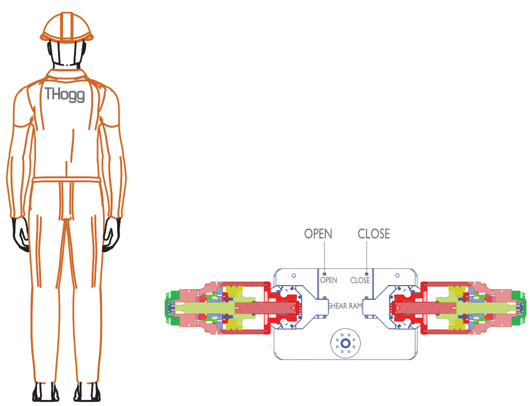


KEY TO DRAWING LAYERS

Blue Pod	110,120,255
BOP Equipment	Multi-colored for cutaway clarity
Choke Line	0,0,255
Kill Line	255,0,0
Yellow Pod	225,200,10

(SOURCE: US DOT, BTS, SafeOCS Program)

Figure F. Example Schematic for Surface BOP Stack Control System



KEY TO DRAWING LAYERS
BOP Equipment Multi-colored for cutaway clarity

(SOURCE: US DOT, BTS, SafeOCS Program)

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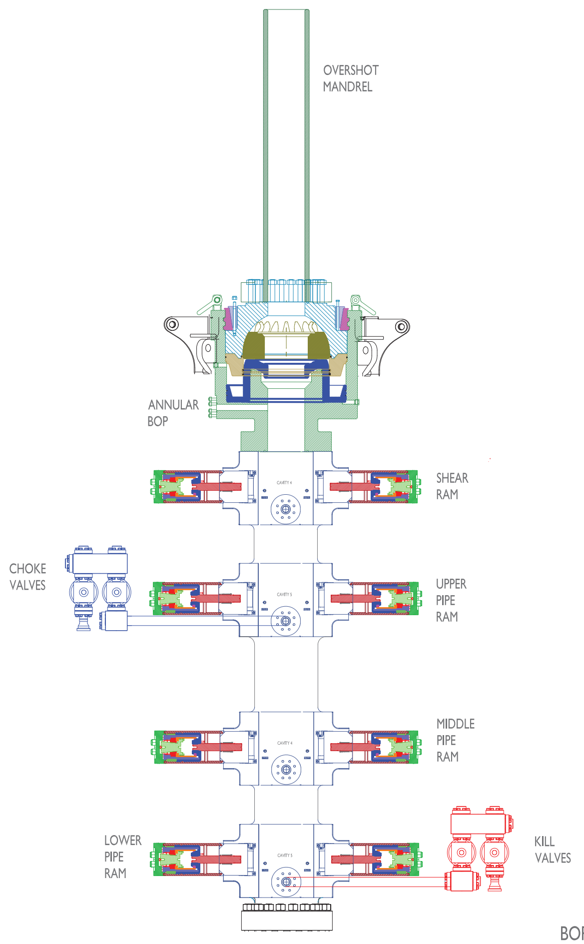
Figure G. Example Schematic for Surface BOP Stack



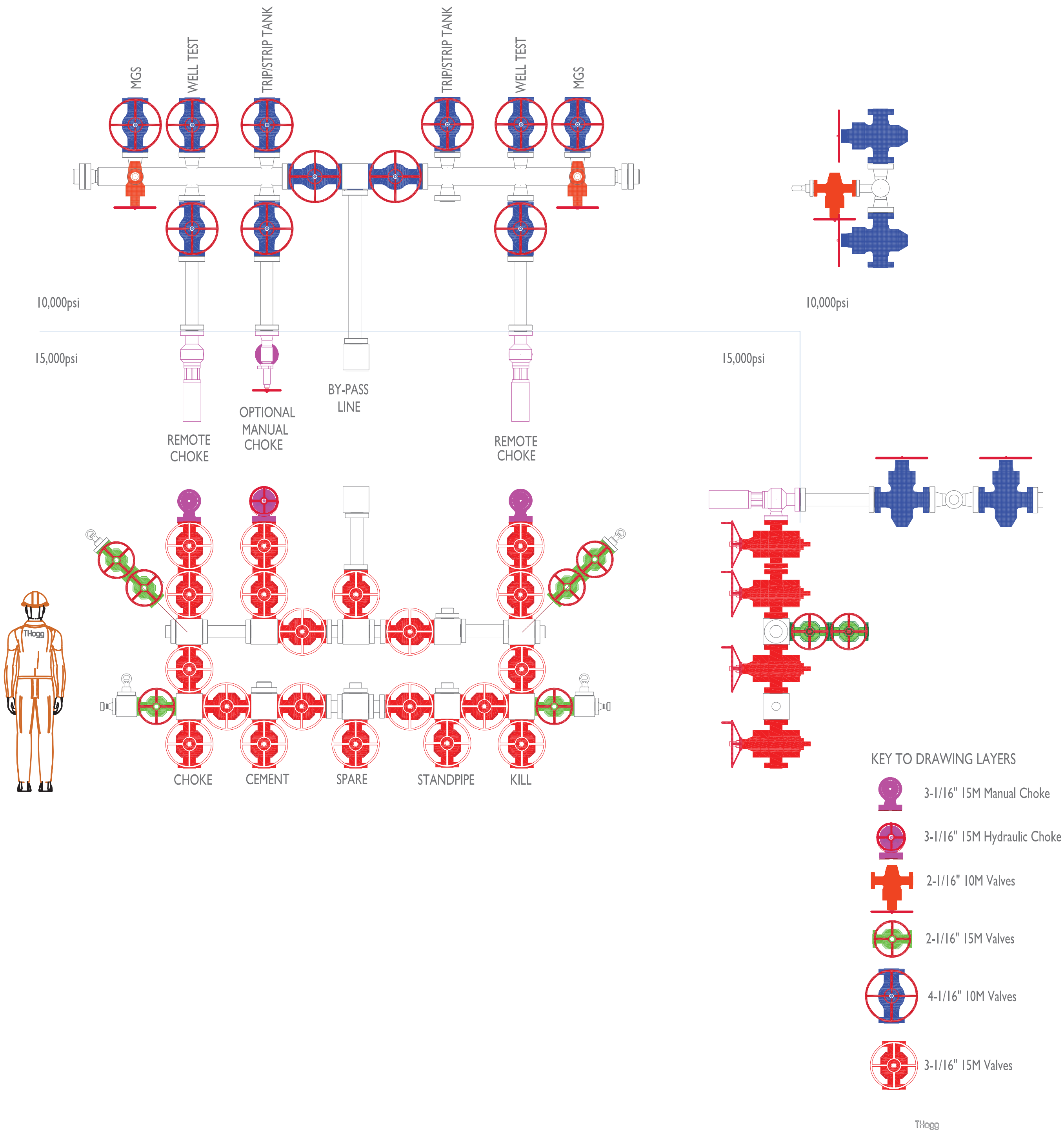
KEY TO DRAWING LAYERS

BOP Equipment	Multi-colored for cutaway clarity
Choke Line	0,0,255
Diverter Spool	60,120,80
Kill Line	255,0,0

THogg

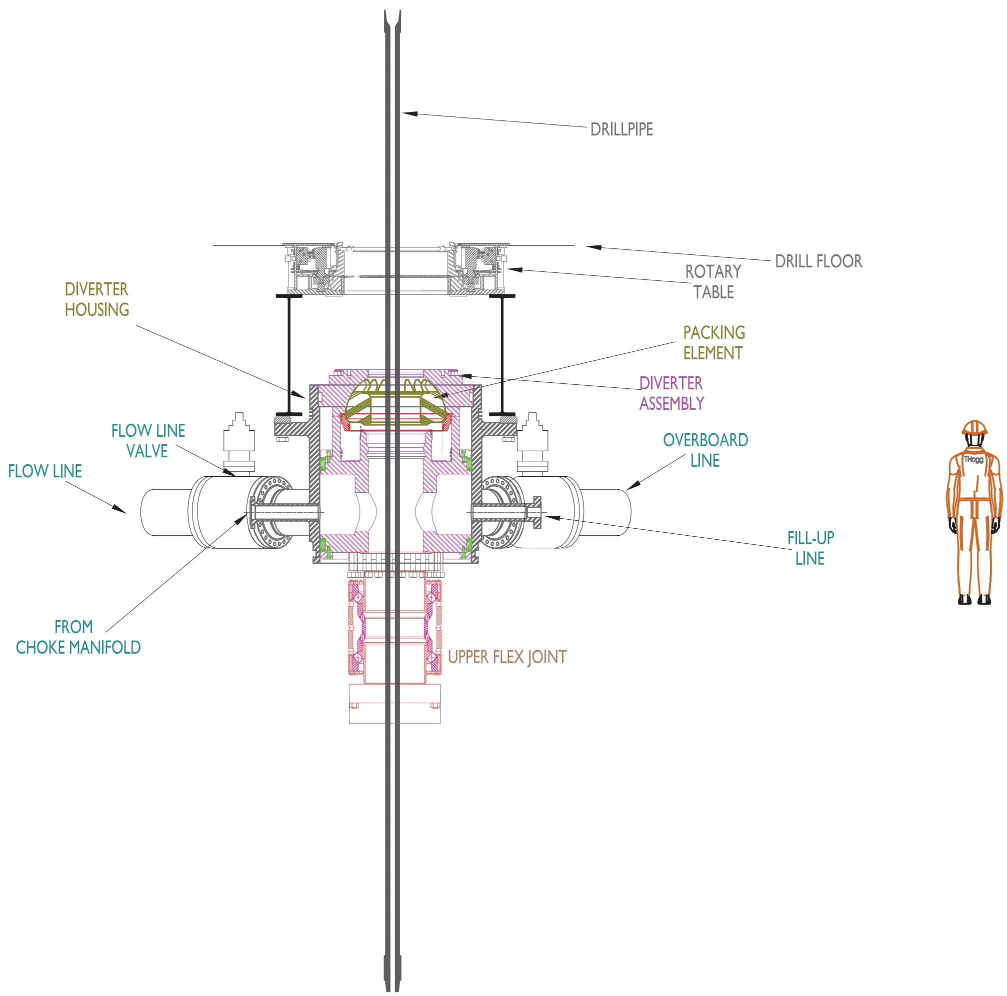
(SOURCE: US DOT, BTS, SafeOCS Program)

Figure H. Example Schematic for Choke Manifold



(SOURCE: US DOT, BTS, SafeOCS Program)

Figure I. Example Schematic for Diverter System



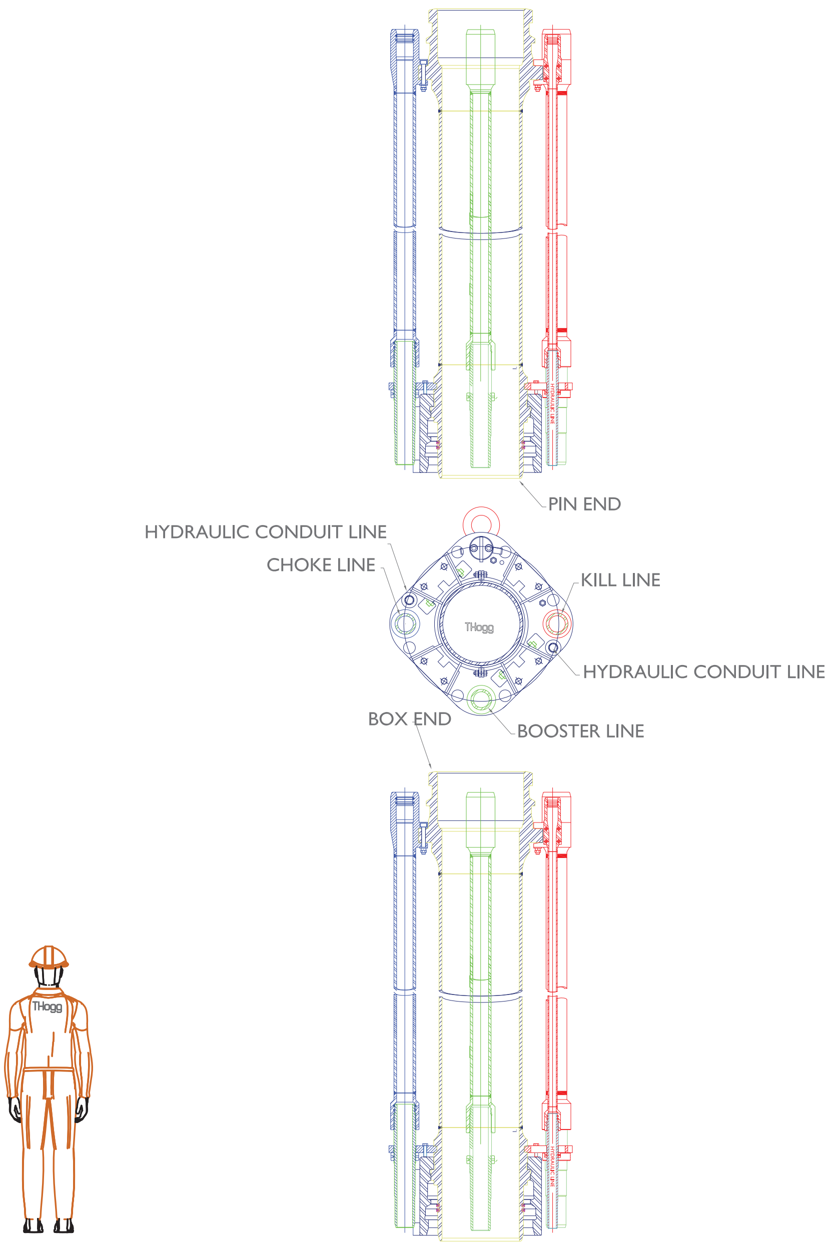
KEY TO DRAWING LAYERS

Diverter Assembly	180,80,180
Diverter Housing	80,80,80
Diverter Pipework	40,140,140
Drill Pipe	50,50,50
Packing Element	130,130,0
Upper Flex Joint	175,125,100

THogg

(SOURCE: US DOT, BTS, SafeOCS Program)

Figure J. Example Schematic for Riser Joints



KEY TO DRAWING LAYERS

Choke Line	0,0,255
Kill Line	255,0,0
Main Tube	0,31,127
Mud Boost Line	0,255,0

THogg

(SOURCE: US DOT, BTS, SafeOCS Program)