WELL CONTROL EQUIPMENT SYSTEMS SAFETY 2020 ANNUAL REPORT

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

WELL CONTROL EQUIPMENT SYSTEMS SAFETY

2020 Annual Report

Acknowledgements

Bureau of Transportation Statistics

Patricia Hu
Director

Rolf Schmitt
Deputy Director

Produced under the direction of:

Demetra Collia
Director of the Office of Safety Data and Analysis

Recommended Citation:

Bureau of Transportation Statistics. *Well Control Equipment Systems Safety – 2020 Annual Report.* Washington, D.C.: United States Department of Transportation, 2020.
https://doi.org/10.21949/1523056

Cover Image Source:

Offshore oil rig at day. Adobe Stock.

Quality Assurance Statement

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

Notice

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

TABLE OF CONTENTS

Executive Summary **1**

Introduction **1**

About SafeOCS 1

Stakeholder Collaboration 2

Context for WCE Events 2

Data Validation and Exposure Measures 4

Analysis Information and Data Adjustments 6

Chapter 1: Numbers at a Glance **7**

Drilling Activity Levels during the COVID-19 Pandemic 8

Sources of WCE Event Reporting 10

Chapter 2: Subsea WCE System Events **11**

Reporting Operators 12

Not-in-Operation Events 13

Events by Subunit 14

Events by Failure Type 16

Detection Methods 17

Root Causes of Events 18

Stack Pull Events 19

Time to Failure 22

Investigation and Analysis 26

Lessons Learned for Subsea BOP Systems 31

Chapter 3: Surface WCE System Events **32**

Reporting Operators 33

Events by Subunit 34

Events by Failure Type 34

Detection Methods 35

Root Causes of Events 36

Stack Pull Events 36

Investigation and Analysis 38

Chapter 4: Conclusion and Next Steps 40

Next Steps: Opportunities for Improving Data Quality 41

Appendix A: Regulatory Reporting Requirement 42

Appendix B: Operational States of WCE Systems 44

Condition-Based Maintenance 45

MIT for Subsea WCE Systems 45

MIT for Surface WCE Systems 47

Appendix C: 2020 Component Population Estimates 49

Appendix D: 2020 Stack Pull Event Summaries 50

Appendix E: Glossary 52

Detection Method Terms 57

Appendix F: Acronyms 58

LIST OF FIGURES

Figure 1: Drilling Activity in the Gulf of Mexico OCS, 2017-2020 9
Figure 2: Drilling Hours Worked, GOM OCS, 2017-2020 9
Figure 3: Sources of WCE Event Reporting, 2020 10
Figure 4: Subsea System Events and Rig Activity by Operator, 2020 12
Figure 5: Subsea System Not-In-Operation Events Relative to Rig Activity, 2020 14
Figure 6: Average Reported Time to Failure, 2017-2020 24
Figure 7: Surface System Events and Rig Activity by Operator, 2020 33
Figure 8: The Cycle of Maintenance, Inspection, and Testing 44

LIST OF TABLES

Table 1: Numbers at a Glance, 2017-2020 7
Table 2: Subsea Systems Numbers at a Glance, 2017-2020 11
Table 3: Not-In-Operation Events by Subunit (Subsea Systems), 2017-2020 15
Table 4: In-Operation Events by Subunit (Subsea Systems), 2017-2020 15
Table 5: Types of Not-In-Operation Events (Subsea Systems), 2017-2020 16
Table 6: Types of In-Operation Events (Subsea Systems), 2017-2020 16
Table 7: Detection Methods for Not-In-Operation Events (Subsea Systems), 2017-2020 17
Table 8: Detection Methods for In-Operation Events (Subsea Systems), 2017-2020 17
Table 9: Root Causes of Not-In-Operation Events (Subsea Systems), 2017-2020 19
Table 10: Root Causes of In-Operation Events (Subsea Systems), 2017-2020 19
Table 11: Root Causes of Subsea Stack Pulls, 2017-2020 20
Table 12: Types of Events Leading to Subsea Stack Pulls, 2017-2020 20
Table 13: Equipment and Types of Failures Associated with Subsea Stack Pulls, 2017-2020 21
Table 14: Reported Time to Failure, 2017-2020 23
Table 15: Time to Failure for Components Associated with Stack Pulls, 2017-2020 25
Table 16: Findings from I&As for Subsea System Events, 2020 27
Table 17: Surface System Numbers at a Glance, 2017-2020 32
Table 18: Not-In-Operation Events by Subunit (Surface Systems), 2017-2020 34
Table 19: In-Operation Events by Subunit (Surface Systems), 2017-2020 34

Table 20: Types of Not-In-Operation Events (Surface Systems), 2017-2020 35
Table 21: Types of In-Operation Events (Surface Systems), 2017-2020 35
Table 22: Detection Methods for Not-In-Operation Events (Surface Systems), 2017-2020 35
Table 23: Detection Methods for In-Operation Events (Surface Systems), 2017-2020 35
Table 24: Root Causes of Not-In-Operation Events (Surface Systems), 2017-2020 36
Table 25: Root Causes of In-Operation Events (Surface Systems), 2017-2020 36
Table 26: Types of Events Leading to Surface Stack Pulls, 2017-2020 37
Table 27: Root Causes of Surface Stack Pulls, 2017-2020 37
Table 28: Equipment and Types of Failures Associated with Surface Stack Pulls, 2017-2020 38
Table 29: Findings from I&As for Surface System Events, 2020 39
Table 30: Estimates of Subsea WCE Components by Subunit, 2020 49
Table 31: Estimates of Surface WCE Components by Subunit, 2020 49
Table 32: Subsea Stack Pull Summaries, 2020 50
Table 33: Surface Stack Pull Summaries, 2020 51

Executive Summary

The *Well Control Equipment Systems Safety – 2020 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 contains an analysis of reported events involving WCE systems, including blowout preventer (BOP) equipment, and other key information about the events, such as root causes and follow-up actions. Data is presented by WCE system type (subsea or surface) and by when the event occurred (in-operation or not-in-operation).

The coronavirus pandemic was likely a significant factor in an overall decrease in both event reporting and well activity in 2020. SafeOCS received 629 WCE failure event notifications (608 subsea system notifications and 21 surface system notifications) for 2020, a 36.8 percent decrease from 2019. An additional 129 failure events were identified through a review of well activity report (WAR) data, bringing the total number of known WCE failure events in 2020 to 758. Well activity decreased by 26.7 percent from 2019 to 2020 as measured by the number of days during which WCE systems were in use (BOP days). When adjusted for well activity, the number of events reported to SafeOCS declined 13.8 percent overall. No leaks of wellbore fluids to the environment, classified as losses of containment, were reported to SafeOCS in 2020, and only one such event has been reported since the data collection began in mid-2016.

Subsea WCE System Events

For subsea WCE systems, 551 not-in-operation events and 57 in-operation events were reported to SafeOCS for 2020, representing a 33.0 percent decline from 2019. When adjusted for well activity, reported subsea system events declined 22.2 percent. Eleven of 19 operators with subsea well operations in the GOM reported equipment failure events for 22 of 26 subsea system rigs with activity. As in previous years, the BOP control systems 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 common root causes were:

- Wear and tear (reported for 33.6 percent of not-in-operation events and 36.8 percent of in-operation events),
- Design issue (19.8 and 17.5 percent), and
- Procedural error (13.1 and 17.5 percent).

Eight events, including three identified in WAR data, resulted in stack pulls. Seven of the subsea stack pulls in 2020 involved a leak of control fluid.

Surface WCE System Events

For surface WCE systems, 12 not-in-operation events and nine in-operation events were reported to SafeOCS for 2020, representing a 75.9 percent decline from 2019. When adjusted for well activity, reported surface system events declined 56.6 percent. Eight of 17 operators with surface well operations in the GOM reported equipment failure events for 10 of 24 surface system rigs with activity. As in previous years, the BOP control systems 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. A root cause of wear and tear was attributed to all reported events in 2020. Nine events, including six identified in WAR data, resulted in stack pulls. Four of the surface stack pulls in 2020 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 *2020 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 an analysis of reported events involving WCE systems, including blowout preventer (BOP) equipment, an analysis of root causes, a summary of lessons learned from failure event investigations, and a discussion of opportunities to improve data quality and accessibility.

About SafeOCS

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

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

[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).

information, and submit failure reports to the original equipment manufacturer. This is the fifth 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). The JIP developed and manages RAPID-S53, the Reliability and Performance Information Database for Well Control Equipment covered under API Standard 53.
- **Internal Review Team**: SafeOCS retained experts in drilling operations, production operations, equipment testing, and well control equipment design and manufacturing. The subject matter experts reviewed event reports, validated, and clarified BTS and BSEE data, and provided input to this report.
- **BSEE**: BSEE provided BTS with well-related data used for data validation, benchmarking, and development of exposure measures, described under *Data Validation and Exposure Measures* (page 4).

Context for WCE Events

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

---

[2] Prior to 2019, the annual reports were titled *Blowout Prevention System Safety Events*.
[3] Well operations include drilling, completion, workover, and decommissioning activities. 30 CFR 250.700.

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

WCE systems are critical to 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:

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

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

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 operationally disruptive event followed, such as a BOP stack pull. The following factors were considered in determining how to present the data:

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

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

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

Data Validation and Exposure Measures

BTS used data provided by BSEE to validate SafeOCS data and develop exposure measures that help provide context for the failures. BTS validated submitted data by reviewing well activity reports (WARs), which oil and gas operators must submit to BSEE weekly for active well operations in the Gulf of Mexico OCS Region, per 30 CFR 250.743. WARs were also used to identify WCE failure events that were not reported to SafeOCS.

---

[5] An ROV is required under 30 CFR 250.734 and provides a live video feed together with the capability to open and close specific control valves and perform some other simple tasks.
[6] On a subsea system, the BOP stack, the BOP control pods, hoses, cables, and the marine drilling riser are all located underwater when in use and are therefore inaccessible. The subsea BOP stack equipment is densely packed into a handling and protection frame, making access difficult and time-consuming. All the equivalent equipment on a surface system is above water and joined together using industry standard connections, making access easier.
[7] A well can experience a blowout when the formation's pressure is higher than the drilling fluid's hydrostatic pressure.

BTS also used BSEE data sources including WARs to develop exposure measures that quantify the population of equipment subject to failure and its characteristics. These exposure measures, sometimes referred to as denominator or normalizing data because they represent the population based on statistical values, facilitate comparisons over time and between different types of WCE. WAR data is used to develop several measures (numbered one through seven below) that approximate the number of active operators and the amount of rig activity.[8] An additional measure, wells spudded (number eight below), is developed from the BSEE boreholes table and provides information on the extent of new well activity in 2020. The measures include the following:

1. **Active operators**: The number of operators conducting rig operations.
2. **Wells with activity**: The number of wells worked on by rigs, regardless of the well operation.
3. **Rigs with activity**: The number of rigs with operations.
4. **BOP days**: The number of days during which some or all the WCE components may have been in use 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 an estimated increase in WCE components.[9] The number of **in-operation BOP days** is the subset of BOP days when the BOP system was in operation.
5. **BOP stack runs**: The number of times a subsea BOP stack was run (deployed) from the rig to the wellhead. This number also includes when the stack was moved from one location to another while staying submerged (i.e., well hopping).
6. **BOP stack starts**: The number of times a surface BOP stack was assembled on the surface wellhead.

[8] Non-rig WARs are excluded. Rig WARs are included for all well operation types.
[9] The component count of a subsea system rig with two BOP stacks divided by the component count of a subsea system rig with one BOP stack = 1.48. The details of these estimates are provided in the SafeOCS supplement, *WCE Estimated System Component Counts*, published separately.

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

Analysis Information and Data Adjustments

- The terms *subsea* and *surface* reference the type of applicable BOP system, not the equipment's location (above or below the waterline); i.e., subsea exposure measures apply to rigs with subsea BOP systems, and surface exposure measures apply to rigs with surface BOP systems.
- Due to rounding, numbers in tables and figures may not add up to totals.
- SafeOCS may receive WCE event notifications after the publication of annual reports. If notifications are received after publication that meaningfully impact this report's results and conclusions, an addendum may be published.
- Numbers are adjusted in each annual report to reflect information provided after publication and may vary from those reported in the previous annual report. All results and references to previous data in this report represent updated numbers unless otherwise stated.
- Well intervention equipment failure notifications reported to SafeOCS are excluded from this report due to data collection limitations for these types of equipment. This is an area for improvement noted in Chapter 4.

CHAPTER 1: NUMBERS AT A GLANCE

This report is based on data from 629 WCE failure event notifications (608 subsea system and 21 surface system events) submitted to SafeOCS for 2020 (see Table 1). All reported events occurred in the GOM OCS, which accounts for over 99 percent of annual oil and gas production on the OCS.[10] The number of reported WCE events decreased 36.8 percent from 2019. As in previous years, most events (89.5 percent) occurred while not in operation. None of the events in 2020 resulted in a leak of wellbore fluids to the environment, classified as a loss of containment.

Overall, well activity decreased from 2019 to 2020, as measured by the following:

Table 1: Numbers at a Glance, 2017-2020

MEASURE	2017	2018	2019	2020
WELLS				
Wells with Activity	325	389	397	264
Wells Spudded	152	193	188	115
RIGS				
Rigs with Activity	60	59	63	50
Rigs with Reported Events	47	40	36	32
OPERATORS				
Active Operators	27	32	29	27
Reporting Operators	18	14	13	14
BOP DAYS				
Total BOP Days	16,072	17,073	16,990	12,462
In-Operation BOP Days	9,949	10,739	10,515	7,080
Not-in-Operation BOP Days	6,123	6,334	6,475	5,382
COMPONENT EVENTS				
Total Events Reported*	1,420	1,196	995	629
Overall Event Rate**	88.4	70.1	58.6	50.5
In-Operation Events	245	171	152	66
In-Operation Event Rate	24.6	15.9	14.5	9.3
In-Operation Events per Well	0.8	0.4	0.4	0.3
Not-in-Operation Events	1,175	1,025	843	563
Not-in-Operation Event Rate	191.9	161.8	130.2	104.6
Not-in-Operation Events per Well	3.6	2.6	2.1	2.1
LOC EVENTS				
Loss of Containment Events	1	0	0	0

KEY: In-operation Not-in-operation
NOTES:
* Total Events Reported excludes any events identified in WAR data.
** Event Rate is the number of events that occurred per 1,000 BOP days.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

- Days WCE components were in use, *BOP days* (26.7 percent decrease)
- Wells with activity (33.5 percent decrease)
- Wells spudded (38.8 percent decrease)
- Rigs with activity (20.6 percent decrease)

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

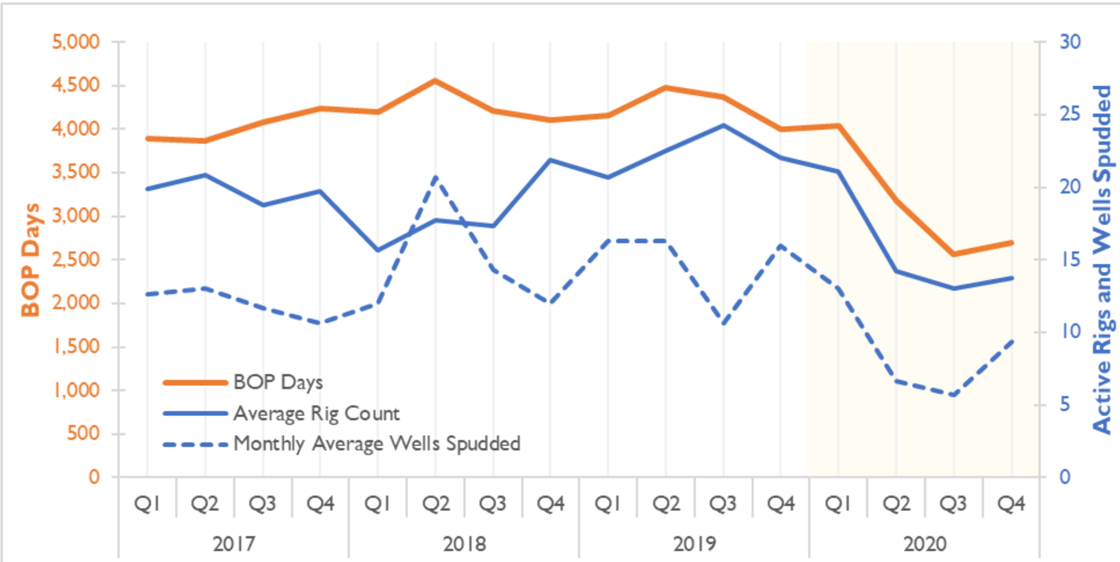
When adjusted for well activity, reported events declined 13.8 percent, from 58.6 events per 1,000 BOP days in 2019 to 50.5 in 2020, and similar declines were observed for the not-in-operation and in-operation event rates. As seen in Table 1, event rates have declined each year since 2017. About the same number of not-in-operation events per well with activity (2.1) were reported in 2020 compared to 2019, while the number of in-operation events per well with activity declined from 0.4 to 0.3.

Drilling Activity Levels during the COVID-19 Pandemic

The coronavirus pandemic was likely a significant factor in the overall decrease in drilling activity levels in 2020, as reflected by a sharp decrease in the second quarter, when the economy slowed dramatically (Figure 1). Demands on the U.S. transportation system fell significantly, with schedules and ridership for commercial airlines, rail, and transit systems dropping to record lows as passenger travel declined.[11] These rapid changes increased uncertainty in the upstream demand for oil and gas. In addition, concern for the health of the crews contributed to lowered drilling activity levels due to partial or full facility evacuations because of positive COVID cases. Drilling hours worked in the GOM OCS also declined in 2020, dropping about 24.7 percent from 2019 (25.5 million to 19.2 million), as shown in Figure 2. However, using hours worked as a measure of relative participation in the SafeOCS WCE failure reporting program, participation remained high. Operators who reported WCE failure events contributed 91.5 percent of all drilling hours worked in 2020.

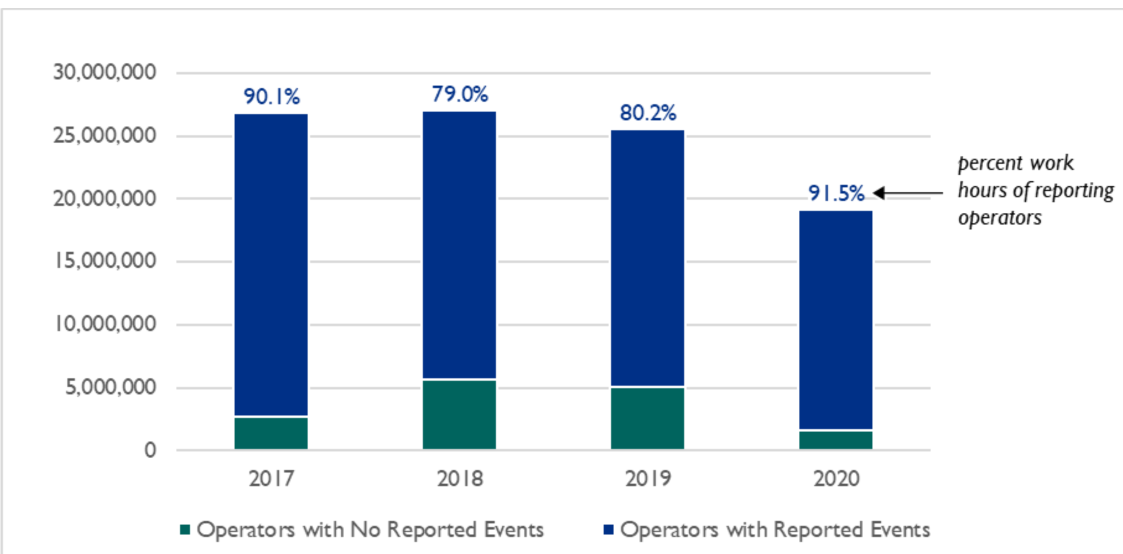
[11] U.S. Department of Transportation, Bureau of Transportation Statistics, *Transportation Statistics Annual Report 2020* (Washington, DC: 2020). https://doi.org/10.21949/1520449

Figure 1: Drilling Activity in the Gulf of Mexico OCS, 2017-2020



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

Figure 2: Drilling Hours Worked, GOM OCS, 2017-2020

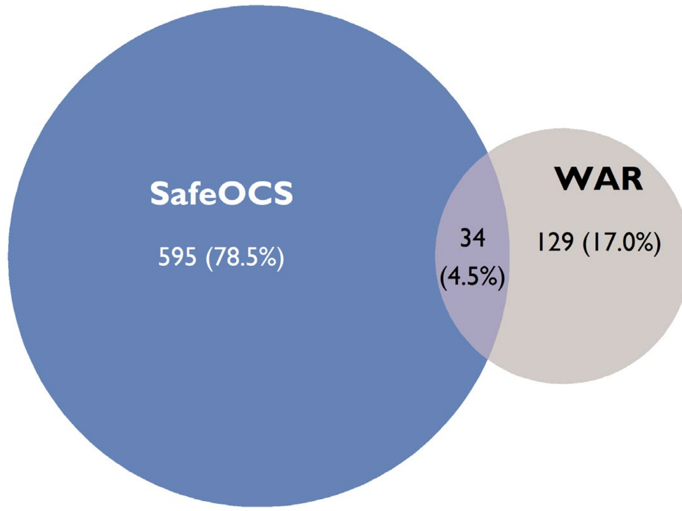


NOTE: Includes both operator and contractor work hours. Reporting operators are those that submitted at least one event notification to SafeOCS.
SOURCE: U.S. DOT, BTS, SafeOCS Program. Work hours from BSEE OCS Performance Measures data.

Sources of WCE Event Reporting

Figure 3 shows the number of WCE failure events reported to SafeOCS and identified in WARs. WAR data was evaluated to cross-reference the timing and occurrence of failures and identify those that may not have been reported to SafeOCS, resulting in a better approximation of the complete set of failure events that occurred in the GOM OCS in 2020. In total, 758 distinct WCE failure events were identified, 629 (83.0 percent) of which were reported to SafeOCS, and the remainder (87 subsea BOP system events and 42 surface system events) were identified in WAR data. Importantly, due to limited available event information, the failures identified in WAR data are excluded from the aggregated statistics presented in this report, except for stack pull events.

Figure 3: Sources of WCE Event Reporting, 2020



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

Chapter 2: Subsea WCE System Events

A subsea WCE system involves a subsea BOP and associated equipment such as BOP control systems, BOP stack, riser system, diverter, choke manifold, and auxiliary equipment. Table 2 lists measures related to GOM OCS subsea wells with activity, together with event data, during each of the last four years. Overall, 608 events were reported for subsea BOP systems in 2020, representing a 33.0 percent decline from 2019. When adjusted for well activity, reported subsea system events declined 22.2 percent, from 91.9 events per thousand BOP days in 2019 to 71.5 events in 2020. As in previous years, most events (90.6 percent) were detected while not in operation, with approximately 9.7 not-in-operation events reported for each in-operation event.

Table 2: Subsea Systems Numbers at a Glance, 2017-2020

MEASURE	2017	2018	2019	2020
WELLS				
Wells with Activity	165	172	189	142
Wells Spudded	87	107	102	74
RIGS				
Total Rigs with Activity	32	31	29	26
With One Subsea Stack	10	9	8	6
With Two Subsea Stacks	22	22	21	20
Rigs with Reported Events	29	24	21	22
OPERATORS				
Active Operators	17	16	20	19
Reporting Operators	11	10	10	11
BOP DAYS				
Total BOP Days	10,900	10,135	9,883	8,501
In-Operation BOP Days	6,334	5,672	5,272	4,345
Not-in-Operation BOP Days	4,566	4,463	4,611	4,156
COMPONENT EVENTS				
Total Events Reported*	1,305	1,127	908	608
Overall Event Rate	119.7	111.2	91.9	71.5
In-Operation Events	187	136	108	57
In-Operation Event Rate	29.5	24.0	20.5	13.1
In-Operation Events per Well	1.1	0.8	0.6	0.4
Not-in-Operation Events	1,118	991	800	551
Not-in-Operation Event Rate	244.9	222.0	173.5	132.6
Not-in-Operation Events per Well	6.8	5.8	4.2	3.9
BOP STACK MOVEMENTS				
Total Stack Runs	200	178	212	160
Successful Runs	167	152	158	138
Stack Pulls	10	8	8**	8**
LOC EVENTS				
Loss of Containment Events	1	0	0	0

KEY: In-operation Not-in-operation

NOTE:

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

** Includes three stack pulls identified in WAR for 2020. For 2019, WAR data was evaluated for subsea stack pulls, but none were identified.

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

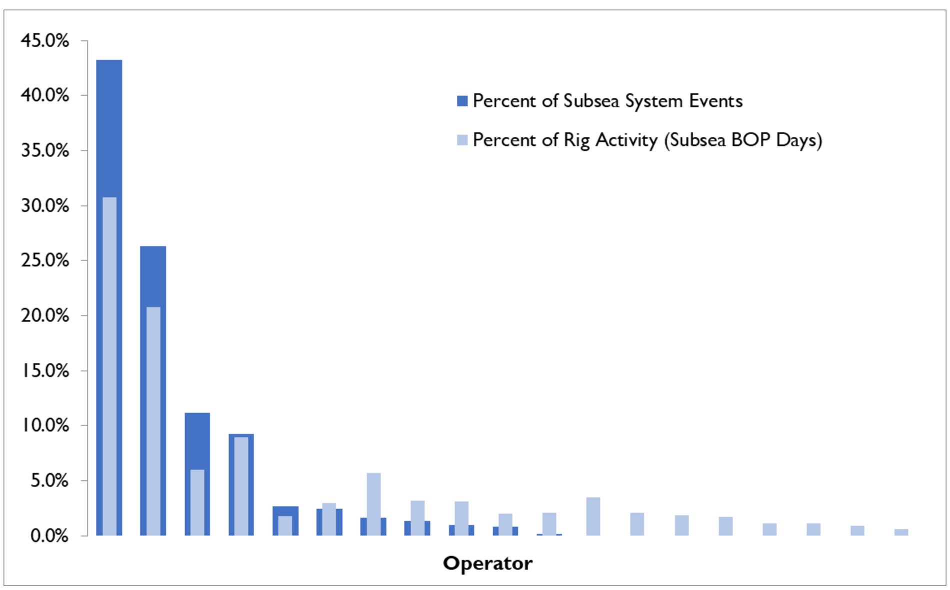
Table 2 shows that the number of subsea wells with activity decreased by 24.9 percent and the number of BOP days decreased by 14.0 percent, with a fleet three rigs smaller. On average, each subsea system rig conducted well operations on 5.5 GOM OCS wells in 2020, compared to 6.5 in 2019.

Considering both stack pulls reported to SafeOCS and those identified in WAR data, eight total stack pulls were recorded in 2020, the same total as in 2019. There were 160 total subsea BOP stack runs,[12] and 138 successful stack runs—meaning the equipment passed all initial latch-up testing and went into operation—for 142 wells with activity in 2020. More stack runs than wells mean that the stack was deployed more than one time on a single well. This may happen, for example, when the stack is retrieved for a weather event and later redeployed, or when an equipment issue is identified before completion of initial testing, and the stack is retrieved to correct it and later redeployed. About 5.8 percent (eight of 138) of successful subsea BOP stack runs eventually led to a stack pull in 2020, a slight increase from 5.1 percent in 2019.

Reporting Operators

Figure 4 shows subsea system events and rig activity (measured in BOP days) for the 19 active operators with subsea system well operations in 2020. The 11 reporting operators represent most of the drilling activity

Figure 4: Subsea System Events and Rig Activity by Operator, 2020



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

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

as measured by their proportion of subsea BOP days (87.2 percent). All but four of the 26 active rigs were represented in event reporting (84.6 percent), an increase from 72.4 percent in 2019.

Not-in-Operation Events

Not-in-operation means that the equipment is being maintained, inspected, or tested before or after being in use. Events occurring in this phase have lower safety and environmental risk than events occurring while equipment is in use. It is not until the BOP stack has been connected to the wellhead and all initial subsea testing has been completed that the system is in operation. In general, more events are detected while not in operation than in operation, as seen in the aggregated statistics presented in Table 2.

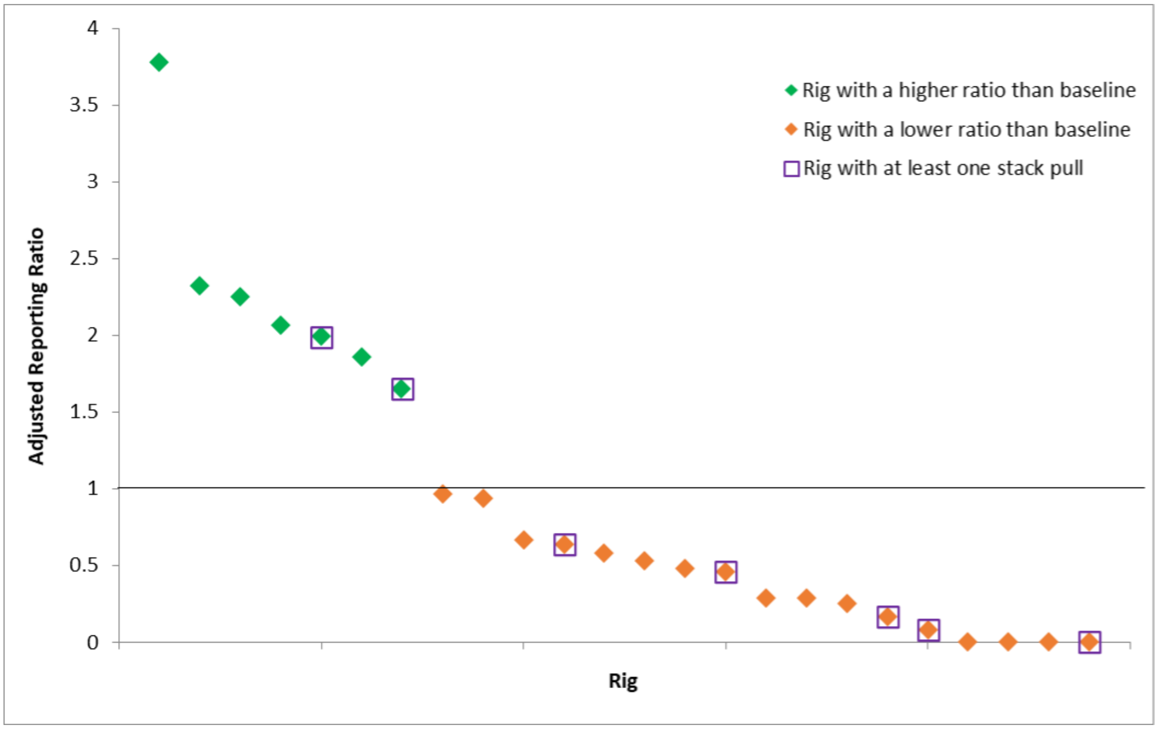
A comparative analysis was performed to evaluate the relationship between not-in-operation events and a more operationally disruptive in-operation event, such as a stack pull. To account for varying levels of activity between rigs, each rig's reporting ratio was adjusted using stack runs as a surrogate measure of rig activity:

$$\text{Adjusted ratio for Rig "A"} = \frac{\text{Rig A's proportion of not-in-operation events}^{13}}{\text{Rig A's proportion of stack runs}^{14}}$$

Figure 5 shows the ratio for each rig with a subsea BOP and not-in-operation activity in 2020.[15] The line intersecting the graph at the value of 1.0 represents the baseline reporting ratio where a rig's not-in-operation events are proportional to its activity level relative to other rigs. A ratio greater than 1.0 indicates potentially disproportionately high reporting of not-in-operation events, while a ratio less than 1.0 indicates potentially disproportionately low reporting of not-in-operation events. As shown in the figure, seven rigs are above the baseline, and 17 rigs are below it.

[13] Rig A's not-in-operation events divided by the total not-in-operation events for all rigs.
[14] Rig A's stack runs divided by the total stack runs for all rigs.
[15] Two active rigs reported only in-operation activity and are not shown in the figure.

Figure 5: Subsea System Not-In-Operation Events Relative to Rig Activity, 2020



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

Figure 5 also shows which rigs experienced stack pulls (shown as an overlaid, outlined shape). Of the seven rigs with higher relative reporting of not-in-operation events, two experienced at least one stack pull (28.6 percent). Of the 17 rigs with lower relative reporting of not-in-operation events, five experienced at least one stack pull (29.4 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), the same proportion as in 2019. 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).

Events by Subunit

Generally, subunits with more components have more failures, and the observed distribution of reported failure events supports this. Table 3 and Table 4 show that the BOP control systems, which have the most redundancies, carried the greatest numbers of events in 2020 and in prior years. The BOP control systems contain more than three times as many components as the

BOP stack, as shown in the estimates provided in Appendix C, Table 30, partially explaining the more than four times as many events attributed to the control systems than the BOP stack in 2020.

The BOP stack—which has redundancies such as multiple annulars, rams, and side outlet valves, but not multiple 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 more accessible than other systems. Neither the diverter system, which is moderately accessible, or the riser system, which is not accessible while in use, offer any redundancies. As in 2018 and 2019, no 2020 in-operation 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.

Not all components have the same likelihood of failure. For example, just three reported events in 2020 were attributed to the riser system, though it has the highest component population estimate after the BOP control systems (see Table 30). This may be explained by the fact that the riser system predominantly consists of heavy wall pipes and static seals, as opposed to the dynamic seals on moving pistons, which are more subject to wear because of movement.

Table 3: Not-In-Operation Events by Subunit (Subsea Systems), 2017-2020

SUBUNIT	2017-19 (n=2,909)	2020 (n=551)
BOP CONTROL SUBUNITS		
BOP Primary Control System	67.5%	66.4%
BOP Emergency Control System	5.4%	6.5%
BOP Secondary Control System	4.2%	5.6%
OTHER SUBUNITS		
Auxiliary Equipment	0.1%	0.2%
BOP Stack System	17.3%	16.9%
Choke Manifold System	1.5%	0.9%
Diverter System	1.8%	3.1%
Riser System	2.3%	0.4%

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

Table 4: In-Operation Events by Subunit (Subsea Systems), 2017-2020

SUBUNIT	2017-19 (n=431)	2020 (n=57)
BOP CONTROL SUBUNITS		
BOP Primary Control System	49.0%	45.6%
BOP Emergency Control System	3.0%	8.8%
BOP Secondary Control System	2.3%	1.8%
OTHER SUBUNITS		
Auxiliary Equipment	1.6%	0.0%
BOP Stack System	10.0%	14.0%
Choke Manifold System	16.2%	5.3%
Diverter System	15.3%	22.8%
Riser System	2.6%	1.8%

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

Events by Failure Type

As shown in Table 5 and Table 6, most events (82.9 percent of not-in-operation events and 72.0 percent of in-operation events) in 2020 were a type of leak, similar to previous years. Those leaks are typically the result of worn or damaged elastomeric seals rather than damage to the more robust steel-based components.

The external leaks in Table 5 and Table 6 capture all reported external leaks regardless of leakage rate. All reported external leaks were leaks of a water-based BOP control fluid, which typically pose a lower risk to the environment than wellbore fluids. Leaks of wellbore fluids would be classified as losses of containment, none of which were reported in 2020, and only one has been reported since the data collection began in mid-2016. In addition, external leaks do not include venting of BOP fluid into the sea during function testing. Such venting is part of the system design and is not the result of an equipment failure event.

Table 5: Types of Not-In-Operation Events (Subsea Systems), 2017-2020

EVENT TYPE	2017-19 (n=2,909)	2020 (n=551)
LEAKS		
External Leak	53.1%	54.4%
Internal Leak	24.1%	28.5%
Undetermined Leak	0.1%	0.0%
OTHER		
Communication / Signal Issue	2.6%	2.9%
Electrical Issue	1.8%	1.5%
Fail to Function on Command	2.5%	3.1%
Inaccurate Indication	2.3%	1.8%
Mechanical Issue	12.1%	4.9%
Process Issue	1.0%	1.5%
Unintended Operation	0.1%	0.0%
Other	0.3%	1.5%

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

Table 6: Types of In-Operation Events (Subsea Systems), 2017-2020

EVENT TYPE	2017-19 (n=431)	2020 (n=57)
LEAKS		
External Leak	41.8%	43.9%
Internal Leak	28.8%	28.1%
Undetermined Leak	0.0%	0.0%
OTHER		
Communication / Signal Issue	9.3%	3.5%
Electrical Issue	3.9%	5.3%
Fail to Function on Command	3.5%	7.0%
Inaccurate Indication	3.7%	3.5%
Mechanical Issue	5.6%	5.3%
Process Issue	2.8%	3.5%
Unintended Operation	0.2%	0.0%
Other	0.5%	0.0%

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

Detection Methods

When the equipment is not in operation, it is undergoing both periodic and corrective maintenance. This maintenance includes inspections, before all 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 7, failures found during corrective and periodic maintenance, inspection, and function and pressure testing (i.e., maintenance, inspection, and testing or MIT) accounted for 77.7 percent of not-in-operation events in 2020 and 82.5 percent from 2017 to 2019, showing that most events are detected through both routine and preventive maintenance before operations begin.

Table 7: Detection Methods for Not-In-Operation Events (Subsea Systems), 2017-2020

	DETECTION METHOD	2017-19 (n=2,909)	2020 (n=551)
	Casual Observation	9.3%	10.5%
	Continuous Condition Monitoring	5.8%	6.0%
	On Demand	0.7%	1.8%
	Periodic Condition Monitoring	1.7%	3.8%
	Corrective Maintenance	1.7%	0.7%
	Periodic Maintenance	5.5%	5.4%
MIT	Inspection	19.1%	13.6%
	Function Testing	40.9%	41.7%
	Pressure Testing	15.3%	16.3%

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

When BOP equipment is in operation, it remains largely on standby, with continuous condition monitoring transmitting and recording pressures, volumes, and electrical equipment status. Table 8 shows the percentage of events detected while well-construction activities were ongoing. The percent of events detected through continuous condition monitoring (17 of 57 events) and on demand (4 of 57 events) were slightly higher in 2020 compared to the 2017-2019 average.

Table 8: Detection Methods for In-Operation Events (Subsea Systems), 2017-2020

	DETECTION METHOD	2017-19 (n=431)	2020 (n=57)
	Casual Observation	14.2%	17.5%
	Continuous Condition Monitoring	20.0%	29.8%
	On Demand	1.6%	7.0%
	Periodic Condition Monitoring	7.2%	7.0%
	Corrective Maintenance	0.5%	0.0%
	Periodic Maintenance	1.2%	0.0%
MIT	Inspection	17.4%	8.8%
	Function Testing	15.3%	19.3%
	Pressure Testing	22.7%	10.5%

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

On demand failures refer to equipment not functioning when required. The four on demand in-operation cases were a leaking diverter assembly seal, a cracked choke gate, a leaking shuttle valve, and a damaged annular packer. None of these events resulted in a stack pull. Of the 10 not-in-operation on demand cases, five were shuttle valves on the same rig in the same week, due to either a leak or blockage, two were leaking diverter flowline seals on the same rig at the same time, one was a hotline hose damaged while retrieving the stack, and the remaining two were a non-communicating pressure switch and a leaking shear seal valve.

Root Causes of Events

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 9 and Table 10 can be broadly grouped based on the parties involved:

- Design issue and QA/QC manufacturing are typically attributable to the original equipment manufacturer (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 onsite or by a root cause failure analysis carried out onshore. 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 9 and Table 10 reflect the latest information received on the root cause of an event.

Table 9: Root Causes of Not-In-Operation Events (Subsea Systems), 2017-2020

ROOT CAUSE	2017-19 (n=2,909)	2020 (n=551)
Design Issue	15.4%	19.8%
QA/QC Manufacturing	8.7%	5.6%
Maintenance Error	11.8%	13.4%
Procedural Error	5.8%	13.1%
Documentation Error	0.3%	11.8%
Wear and Tear	52.7%	33.6%
Other	0.4%	0.4%
NOT DETERMINED		
Inconclusive	0.1%	0.0%
Assessment Pending	3.4%	2.0%
Not Reported	1.2%	0.4%

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

Table 10: Root Causes of In-Operation Events (Subsea Systems), 2017-2020

ROOT CAUSE	2017-19 (n=431)	2020 (n=57)
Design Issue	16.9%	17.5%
QA/QC Manufacturing	4.4%	5.3%
Maintenance Error	6.3%	7.0%
Procedural Error	5.1%	17.5%
Documentation Error	0.9%	8.8%
Wear and Tear	52.2%	36.8%
Other	0.7%	0.0%
NOT DETERMINED		
Inconclusive	0.0%	0.0%
Assessment Pending	11.1%	7.0%
Not Reported	2.3%	0.0%

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

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; however, it was considerably lower in 2020 compared to the 2017-2019 average. A higher percentage of 2020 notifications attributed the failure to procedural error (i.e., an error during operations) or documentation error (e.g., an incorrect torque or pressure rating in a document) than in past years. Of the in-operation events attributed to procedural errors, issues cited include nickel leaching of tungsten-carbide seal plates and debris in shuttle valves. The reported makeup of such debris varied widely and included slivers of flashing from non-metallic seals, corrosion particulates from a metallic part, or other water-borne particles drawn in through open ROV intervention receptacles.

Stack Pull Events

All stack pulls are, by definition, in-operation events. They occur only if the equipment cannot be repaired in place or if redundant equipment would not meet requirements to continue operations without the failed component. In 2020, five stack pulls were reported to SafeOCS and an additional three stack pulls were identified in WAR, for a total of eight subsea stack pulls. Considering only the stack pulls reported to SafeOCS, 8.8 percent of in-operation events in 2020 (5 of 57) led to a stack pull, compared to 7.4 percent in 2019 (8 of 108).

The event types attributed to subsea stack pulls over the last four years are shown in Table 11. As in previous years, external leaks of hydraulic fluids are the predominant failure type leading to stack pulls in 2020.

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. Additionally, retrieval of the LMRP for a weather-related event or evacuation is not considered a stack pull.

Table 11: Root Causes of Subsea Stack Pulls, 2017-2020

ROOT CAUSE	2017-19	2020
Design Issue	6	1
QA/QC Manufacturing	1	-
Maintenance Error	3	-
Procedural Error	4	1
Wear and Tear	4	2
NOT DETERMINED		
Assessment Pending	8	1
Unknown to SafeOCS*	-	3
TOTAL	**26**	**8**

KEY: In-operation
NOTES:
* The root causes of 3 stack pulls identified in WAR in 2020 are unknown to SafeOCS.
\- Dash indicates a count of zero.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Root Causes of Subsea Stack Pulls

Table 12 shows the distribution of root causes for events leading to subsea stack pulls. Two stack pulls in 2020 had a root cause of wear and tear, one was attributed to a design issue, one was attributed to a procedural error, and one was listed as undergoing additional investigation and analysis. For the wear and tear cases, one was the result of a leaking check valve with 39 months of use, and the other was the result of a leaking accumulator gas valve after 16 months of use. For the three stack pulls identified in WAR, no definitive root cause was cited.

Table 12: Types of Events Leading to Subsea Stack Pulls, 2017-2020

EVENT TYPE	2017-19	2020
LEAKS		
External Leak	14	5
Internal Leak	6	2
OTHER		
Communication / Signal Issue	1	-
Fail to Function on Command	2	1
Mechanical Issue	2	-
Process Issue	1	-
TOTAL	**26**	**8***

KEY: In-operation
NOTES:
* 2020 count includes three stack pulls identified in WAR. For 2019, WAR data was evaluated but no subsea stack pulls were identified. Prior years do not include events identified in WAR.
\- Dash indicates a count of zero.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Component Combinations Associated with Subsea Stack Pulls

Table 13 shows the components and event types for events leading to subsea stack pulls from 2017 to 2020. For 2020, seven of the eight reported stack pulls involved a leak of control fluids. Four subsea stack pulls in 2020 occurred on component and failure type combinations that had not experienced a reported stack pull in previous years: an annular preventer packing element failing to function on command, an external leak from an SPM valve on the deadman autoshear system, and external leaks of a check valve and a gas valve on the BOP control pod.

Table 13: Equipment and Types of Failures Associated with Subsea Stack Pulls, 2017-2020

Item	Component	Failure Type	2017-2020		2020 Only	
			In-Operation Events	Stack Pulls	In-Operation Events	Stack Pulls
Annular Preventer	Operating System Seal	External Leak	2	1	-	-
		Internal Leak	2	1	-	-
	Packing Element	Fail to Function on Command	1	1	1	1
		Internal Leak	9	3	1	1
Autoshear Deadman EHBS	Piping/Tubing	External Leak	2	2	-	-
	SPM Valve	External Leak	1	1	1	1
		Fail to Function on Command	1	1	-	-
	Timing Circuit	Fail to Function on Command	1	1	-	-
BOP Control Pod	Check Valve	External Leak	1	1	1	1
	Gas Valve	External Leak	1	1	1	1
	Interconnect Cable	Mechanical Issue	1	1	-	-
	Piping/Tubing	External Leak	6	2	1	-
	SPM Valve	External Leak	18	2	1	-
BOP Controls Stack Mounted	Electrical Connector	Communication / Signal Issue	1	1	-	-
	Hose	External Leak	10	1	1	-
	Piping/Tubing	External Leak	4	2	2	1
	Shuttle Valve	External Leak	3	1	-	-
Pipe Ram Preventer	Bonnet Face Seal	External Leak	1	1	-	-
	Ram Block Seal	Internal Leak	15	2	5	-
Riser	Choke and Kill Line	Process Issue	1	1	-	-
Shear Ram Preventer	Bonnet Operating Seal	Internal Leak	3	1	1	1
	Ram Block Hardware	Mechanical Issue	1	1	-	-
	Ram Block Seal	Internal Leak	1	1	-	-
Stack Choke and Kill System	Choke and Kill Valve	External Leak	2	1	-	-
	Flex Loop/Hose	External Leak	3	2	1	1
Telescopic Joint	Packer	External Leak	3	1	-	-
Total			**94**	**34**	**17**	**8**

NOTE: Each of the three 2020 stack pulls identified only in WAR are included in this table as both a stack pull and an in-operation event. Dash indicates a count of zero.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Of the component and failure type combinations associated with a stack pull since 2017, an internal leak of the ram block seal on the pipe ram preventer was the most reported in-operation failure in 2020, with five such events reported, none of which resulted in a stack pull. Two of these failures were on test rams, one was on a variable pipe ram which was not needed during the completion operation underway at the time, and in the remaining two cases operations continued after performing a risk assessment.

Piping/tubing, which covers pipe, tubing, and all associated fittings in various sizes and pressure ratings, has been associated with more subsea stack pulls (six) than any other component from 2017 to 2020. In all these cases, a loose fitting led to the stack pull, due to variety of root causes including maintenance error, QA/QC manufacturing, wear and tear, and others.

The stack pull associated with the riser choke and kill lines is notable because the riser system is rarely associated with a stack pull. In this case, which occurred in 2018, a blockage of cuttings in the riser choke line occurred while circulating drilling fluids.

Further details and summaries of the 2020 subsea stack pull events can be found in Appendix D.

Time to Failure

Examining time to failure, particularly for those events where the component life was unexpectedly short, can indicate that design, manufacturing, or procedural changes may be required to prevent similar events. This section presents a time-to-failure analysis for commonly reported component failures, followed by a similar analysis for components associated with a stack pull. Time to failure is calculated as the period from the reported installation date to the failure date. For 2017 to 2020, most notifications (97.2 percent) included the date of installation.

Time to Failure for Most-Reported Components

Table 14 lists components that had at least 50 notifications from 2017 to 2020,[16] and Figure 6 is a companion visualization showing the average time to failure for each component. For most component types, the reported time to failure varied widely, as seen in their relatively high

[16] Fifty was chosen as the minimum to be consistent with a similar analysis in the 2019 WCE Annual Report.

standard deviations and maximum ranges. This variability may be due to where the component resides (i.e., the equipment subunit or item), its operating environment, and its usage, among other variables. For example, the SPM valve for the wellhead connector is used to latch the connector at the beginning of the well and to unlatch it at the end, while a similar SPM valve on a choke valve operator may be functioned several times every day for months.

Table 14: Reported Time to Failure, 2017-2020

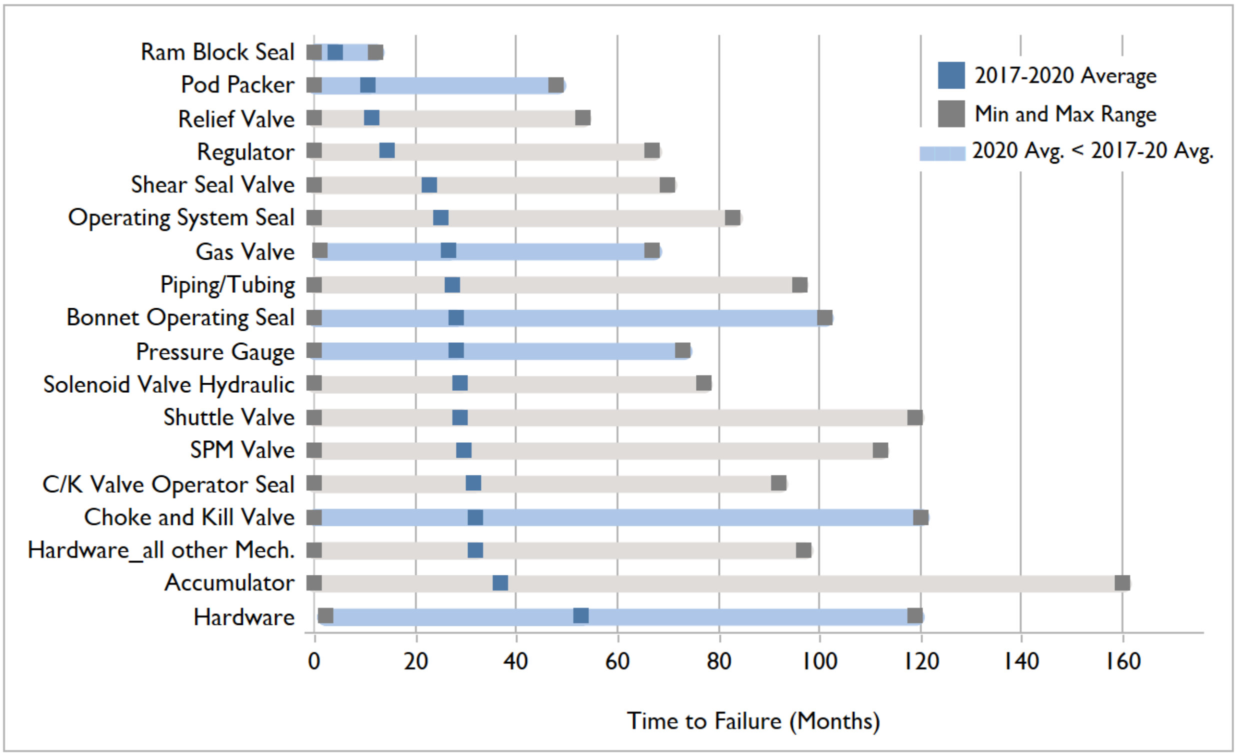
Component (≥50 Notifications)	2017-2020					2020 Only	
	Notifications	Avg. Months to Failure	Standard Deviation (months)	Percent Failed within a Year	Range (months)	Notifications	Avg. Months to Failure
Ram Block Seal	65	4.0	3.0	100.0%	0-12	13	3.5
Pod Packer	53	10.4	15.7	71.7%	0-48	7	5.1
Relief Valve	64	12.4	13.2	70.3%	0-67	9	20.0
Regulator	441	14.4	13.3	55.6%	0-67	79	15.9
Shear Seal Valve	244	22.9	17.5	34.0%	0-70	51	36.1
Operating System Seal	55	25.0	19.8	36.4%	0-83	9	28.7
Gas Valve	59	26.6	18.0	37.3%	1-67	7	22.4
Piping/Tubing	202	27.4	23.5	37.6%	0-96	23	37.6
Bonnet Operating Seal	104	27.9	20.6	27.9%	0-101	21	27.0
Pressure Gauge	68	28.0	22.4	38.2%	0-73	7	20.4
Solenoid Valve Hydraulic	342	28.7	20.8	32.5%	0-77	64	41.2
Shuttle Valve	216	29.0	19.1	21.3%	0-119	50	38.5
SPM Valve	290	29.5	22.8	33.4%	0-112	41	37.0
Choke and Kill Valve Operator Seal	68	31.5	20.8	30.9%	0-92	28	42.1
Choke and Kill Valve	73	31.9	24.9	24.7%	0-120	6	27.0
Hardware_all other Mechanical Elements	75	32.0	23.1	26.7%	0-97	5	63.2
Accumulator	155	36.9	27.8	30.3%	0-160	16	48.7
Hardware	66	52.8	26.8	6.1%	2-119	8	37.9

NOTE: Excludes notifications with missing or invalid installation date. Sorted by lowest average time to failure, 2017-2020.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

While components have different expected lifespans, for most, failing within 12 months of the installation date would be considered earlier than expected. For ram block seals, however, it is not unexpected that all reported failures occurred within the first year after installation, as shown in the table. Ram block seals and annular packers are more affected by cycles (i.e., transitioning between the open and closed positions) and the operating environment (e.g., chemicals and temperature) than time. The time it takes to wear the seals or element is unpredictable; therefore, there is not a specified expected life in terms of time. Relief valves, which also showed a high average rate of failure within the first year, are typically tested and possibly recalibrated every 12 months, potentially contributing to this high rate.

As shown in Figure 6, seven components had a shorter average time to failure for 2020 failures than their 2017-2020 average. For all but hardware, which had a difference of about 15 months, these differences amounted to under one year. This framework could serve as a basis for component-level analysis of changes in average time to failure from year to year.

Figure 6: Average Reported Time to Failure, 2017-2020



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

Time to Failure for Components Associated with Stack Pulls

Not all the component types listed in Table 14 were associated with a reported stack pull. For example, no stack pulls were reported that involved a failed regulator, the most reported failed component from 2017-2020. Table 15 lists time to failure measures for component combinations associated with at least one stack pull during 2017-2020.

The reported time to failure varied widely for most component types, as seen in their relatively high standard deviations and maximum ranges.

Table 15: Time to Failure for Components Associated with Stack Pulls, 2017-2020

Item	Component	Notifications	Avg. Months to Failure	Standard Deviation (months)	Percent Failed within a Year	Range (months)	Stack Pulls (Total In-Operation Events)
Annular Preventer	Operating System Seal	35	24.7	20.1	31.4%	0-83	2 (4)
	Packing Element	25	12.3	18.9	76.0%	0-95	4 (10)
Autoshear Deadman EHBS	Piping/Tubing	39	47.4	12.3	2.6%	5-71	2 (2)
	SPM Valve	26	18.0	20.3	61.5%	1-72	2 (2)
	Timing Circuit	11	29.0	20.2	27.3%	0-59	1 (2)
BOP Control Pod	Check Valve	11	31.0	17.8	9.1%	2-73	1 (2)
	Gas Valve	36	25.6	17.4	38.9%	3-58	1 (1)
	Interconnect Cable	8	17.3	16.4	50.0%	2-50	1 (3)
	Piping/Tubing	51	24.9	19.5	31.4%	0-66	2 (6)
	SPM Valve	164	31.8	21.2	25.6%	0-112	2 (20)
BOP Controls Stack Mounted	Electrical Connector	5	32.2	12.4	0.0%	22-56	1 (2)
	Hose	43	31.7	17.8	18.6%	0-71	1 (13)
	Piping/Tubing	88	17.4	22.6	62.5%	0-96	2 (4)
	Shuttle Valve	202	29.2	19.3	21.8%	0-119	1 (6)
Pipe Ram Preventer	Bonnet Face Seal	9	10.3	16.6	77.8%	0-50	1 (1)
	Ram Block Seal	46	3.8	3.2	100.0%	0-12	2 (15)
Riser	Choke and Kill Line	49	21.6	3.1	2.0%	0-22	1 (1)
Shear Ram Preventer	Bonnet Operating Seal	66	27.5	4.0	10.6%	0-75	1 (3)
	Ram Block Hardware	13	13.6	13.2	69.2%	0-47	1 (1)
	Ram Block Seal	19	4.5	2.1	100.0%	1-9	1 (1)
Stack Choke and Kill System	Choke and Kill Valve	73	31.9	24.9	24.7%	0-120	1 (6)
	Flex Loop/Hose	11	25.1	13.8	18.2%	0-45	2 (3)
Telescopic Joint	Packer	11	12.7	4.7	45.5%	3-19	1 (6)
Total		**1,041**					**34 (114)**

NOTE: Excludes notifications with missing or invalid installation date. Each of the three 2020 stack pulls identified only in WAR are included in this table as both a stack pull and an in-operation event. Total in-operation events exceeds the total shown in Table 13 because this table includes all failure types.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Table 15 shows higher percentages of failure within a year for the packing element on the annular preventer and ram block seals on the pipe ram preventer and shear ram preventer. These components share an important attribute that is different than other elastomer seals. They are all in direct contact with the various chemicals, pressures, and temperatures of wellbore fluids, which are everchanging according to the operations being conducted and are expected to seal on one of a multitude of abrasive dynamic pipes at any point in time. It is normal maintenance practice for these seals to be replaced between each subsea well. Life expectations for these components are not always met due to the changing operating conditions in the well and the unknown number of pressure cycles that will be required, which may explain their higher percentages of failure within a year.

Investigation and Analysis

SafeOCS categorizes investigation and failure analysis (I&A) into three levels: cause immediately known (performed by the rig subsea engineer), subject matter expert (SME) review (performed by more than one subsea engineer), and root cause failure analysis (RCFA) (usually carried out by the OEM or a qualified third-party).[17] 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 an SME review when the cause of the failure is not immediately known, and the investigation does not rise to the level of an RCFA. An RCFA is a detailed investigation conducted for more significant events, and it typically involves the original equipment manufacturer or a qualified third party. If the event resulted in the loss of a well barrier, resulted in an unplanned BOP stack or LMRP pull, or was determined to be a reoccurring event, then escalation to an RCFA is expected, but the rig owner or operator can also conduct an RCFA for any other failure, such as when the SME review level investigation cannot determine the cause or preventive actions.

Table 16 summarizes the findings for 44 I&As that included recommended preventive actions, including 12 I&As at the RCFA level, nine at the SME review level, and the remainder for events with immediately known causes.[18] These I&As pertain to 99 events, 91 of which occurred while not in operation.

[17] For I&As at the SME review level, the SMEs referred to are those who performed the investigation and are employed in the industry. The term does not refer to SMEs retained by SafeOCS.
[18] The table groups events by component issue. Each row may reflect multiple I&As.

Regarding time to failure, about one third of these events occurred within one year of installation, noted in the column titled *Events <1 Year*. Depending on the component, the preventive actions identified in these investigations may help inform equipment owners on how to avoid these earlier-than-expected types of failures in the future. Importantly, for some components failure within one year is not unexpected, such as ram block seals as discussed above.

Table 16: Findings from I&As for Subsea System Events, 2020

	ROOT CAUSE	ROOT CAUSE DETAILS	RECOMMENDED PREVENTIVE ACTION	Total Events	Events <1 Year
1	Design Issue	During a BOP stump test, the lower inner choke valve on the stack choke and kill system was not fully closing. Disassembly and inspection showed damage to the choke and kill valve operator seal. The probable cause was pressure accumulating behind the Polypak o-ring and forcing it out of its groove during the rapid release of pressure from the valve operator.	If OEM tests are satisfactory, equipment owner to install upgraded seal.	3	3
2	Design Issue	A control system shear seal valve, with an obsolete piston in use, leaked externally. In one event, the leak was detected during soak testing, and in another during operations, as detected by the ROV.	Equipment owner to install upgraded piston.	2*	2
3	Design Issue	During preventive maintenance, a deadman autoshear cylinder leaked internally. OEM identified deformed seals and scoring on the upper and lower piston.	The OEM is looking into a new seal design on this particular component.	1	0
4	Design Issue	Equipment owner alerted their fleet about potential damage to the bolting holding the diverter running tool due to a design issue. Upon inspection, mechanical damage was found to the diverter running tool bolting and split ring. Manual handling of the diverter from the rig floor to the cradle may have been a causal factor. Similar findings had been found on other rigs.	Equipment owner updated the maintenance procedure to include more in-depth inspection of the manual tool and revised the handling procedure. An upgraded fastener has been released by the OEM.	1	0

	ROOT CAUSE	ROOT CAUSE DETAILS	RECOMMENDED PREVENTIVE ACTION	Total Events	Events <1 Year
5	Design Issue	An internal hydraulic leak of the choke and kill valve operator on the stack was detected during between well maintenance. OEM determined a rolled o-ring on the choke and kill valve operator piston seal to be a design issue.	OEM has released the latest (T-seal) design.	8	0
6	Design Issue	Several failures of regulator stem o-rings due to intense cycling were reported.	Equipment owner to install a restricted orifice in the supply line to mitigate the instability. Equipment owner also mentions a long-term redesign without further detail.	7*	5
7	Design Issue	Vibrations in the acoustic regulator tubing created a fatigue crack and caused the tubing weld to fail.	Equipment owner to adequately support the tubing, install restricted orifices to reduce instabilities, and require OEM adherence to proper welding procedures.	1	0
8	Design Issue	Low cracking pressure caused a subsea compensator check valve to leak hydraulic fluid externally during testing.	Equipment owner to install a higher cracking pressure check valve.	1	0
9	Design Issue	During initial testing, a ram block packer failed to seal due to a design issue.	Equipment owner to replace ram block packer with upgraded version that OEM will release once qualification of the seal is completed.	1	1
10	Design Issue	OEM found the shear ram preventer's Polypak energizing o-ring trapped pressure and caused lip seal failure.	Equipment owner to follow OEM recommendation that these seals be replaced every 30 months or 800 cycles.	2	0
11	Design Issue	An electrical fault was registered for the BOP control pod subsea control pod electronics. The system fault parameters were determined to be overly sensitive to the presence of high frequency sound.	OEM to modify software to adjust the sensitivity to high frequency sound.	1*	0
12	Design Issue	An alert from the OEM prompted equipment owner examination of a control system relief valve where the spring was found to be broken.	OEM is working on a new design relief valve to be installed in this control circuit.	1	1
13	Design Issue	A retainer ring in a manual regulator in the BOP control pod shattered, damaging an o-ring.	OEM is working on implementing a hydraulic circuit design upgrade.	1	1

	ROOT CAUSE	ROOT CAUSE DETAILS	RECOMMENDED PREVENTIVE ACTION	Total Events	Events <1 Year
14	Design Issue	During initial testing of the deadman autoshear, the timing circuit cylinder was not fully functioning. An investigation determined that the hydraulic system design allowed debris to enter the system downstream of the filter.	Equipment owner to relocate the filter in the hydraulic system. OEM to modify internal design practices to consider sensitive components and upstream sources of debris. OEM to modify shuttle valve gland design.	1	1
15	Design Issue	The choke and kill valve operator springs cracked due to corrosion and hydrogen embrittlement.	OEM to redesign the spring coating/spring metallurgy.	4	0
16	Design Issue	A design issue was determined to cause a subsea compensator to leak hydraulic fluid externally during testing on surface.	Equipment owner replaced subsea compensator with a new style that has a metal cap.	1	0
17	Design Issue	Subsea pod packers leaked due to a lack of axial squeeze, which the OEM determined can be caused by many contributing factors including standoff and packer thickness.	Equipment owner to maintain uniform standoff among packers of the same size and use thicker packers at specific locations know to see an increase in extrusion gap. The OEM to complete an assembly test of all variables and their effect on seal-ability.	3	3
18	QA/QC Manufacturing	A ferrule on the BOP stack tubing was not installed correctly during initial fabrication by the OEM.	Equipment owner recommended that the OEM improve oversight during fabrication.	1	0
19	QA/QC Manufacturing	Control system shear seal valve leaked in vent position only, due to unspecified manufacturing issues.	Equipment owner to replace valve bodies when supplied by the OEM.	2	2
20	QA/QC Manufacturing	Regulator shear seal plates were found broken around the edges due to an assembly error.	OEM created new assembly procedure to be followed.	1	0
21	Maintenance Error	Worn seals were found in the trigger valve after the deadman autoshear system failed during testing. A review of the preventive maintenance system found the trigger valve was not individually listed.	Equipment owner to update the maintenance system to include a standalone preventive maintenance procedure that calls out the components in the deadman autoshear circuit individually.	1	0
22	Maintenance Error	Noticeable amounts of material buildup around the electrical pins on a subsea BOP control pod electrical connector caused a ground fault alarm.	Equipment owner to conduct personnel training to follow procedure and ensure the contact pins remain clean and dry.	1	1

	ROOT CAUSE	ROOT CAUSE DETAILS	RECOMMENDED PREVENTIVE ACTION	Total Events	Events <1 Year
23	Maintenance Error	A loose tubing fitting on the BOP control pod was deemed to have been incorrectly torqued, allowing it to loosen over time in service.	Equipment owner to update maintenance procedure to include checking these fittings during maintenance.	1*	0
24	Maintenance Error	Mud boost gate valve suffered scored gates and seats due to a dislodged (stem to gate) pin attachment.	Equipment owner took the action to review the OEM procedure with field maintenance personnel.	1	1
25	Procedural Error	Debris and corrosion found in control pod shuttle valves with internal leaks.	Equipment owner updated hotstab, and clean fluid management guidelines.	3	0
26	Procedural Error	Deadman autoshear timing circuit piston failed to initiate due to blasting/paint chips in the vent tube causing the piston to stick.	Equipment owner to ensure all hydraulic ports are covered during blasting projects on BOPs.	1	0
27	Procedural Error	Procedure incorrectly called for a dry fire test of an emergency disconnect sequence (EDS) before LMRP liftoff causing damage to the pod receptacle. (See glossary for definition of dry fire testing.)	Equipment owner modified procedure to require a wet (hydraulic) EDS test before an actual LMRP disconnect.	1	0
28	Procedural Error	The seal plates of control system regulators (and one shear seal valve) that leaked were found to have scoring and showed signs of nickel binder leaching. Nickel leaching is the result of the use of demineralized water in the BOP control fluid on systems using Tungsten-Carbide seal plates.	Equipment owner to correct their mix water specification or install remineralizers to combat the issues with binder leaching from these seal plates.	29†	11
29	Procedural Error	Several failures of solenoid valves were found to have scoring on seal plates, with nickel binder leaching a suspected causal factor. In all but one case, the control system solenoid valve was found to be leaking from common vent and all eight solenoids on the bank were rebuilt possibly increasing the total. In the remaining case, the casing shear rams would not close during function testing, possibly due to debris in the solenoid valve.	OEM to update documentation to define minimum mineral content as well as maximum in control fluids makeup. Equipment owner to correct their mix water specification or install remineralizers to combat the issues with corrosion and binder leaching.	16	0

	ROOT CAUSE	ROOT CAUSE DETAILS	RECOMMENDED PREVENTIVE ACTION	Total Events	Events <1 Year
30	Wear and Tear	A leak coming from the check valve on the BOP control pod pilot supply tubing run was detected by the ROV, leading to a stack pull. An investigation determined that wear and tear and a design issue contributed to an o-ring failure on the check valve after 3.3 years of use.	Equipment owner of rigs using this check valve design to upgrade at the earliest opportunity. The upgraded design is a poppet-style valve which provides a redundant seal if the o-ring fails.	1*	0
31	Wear and Tear	The spring was weakened, and the indicator rod was corroded on a wellhead connector after six years of service.	Equipment owner to add the indicator inspection to their 360-day preventive maintenance scope.	1	0

NOTES: Unless noted with one of the below symbols, events listed under *Total Events* were detected while not in operation.
* One of the events occurred in operation.
† Three of the events occurred in operation.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Lessons Learned for Subsea BOP Systems

Most (17) of the preventive actions in 2020 were for component or system redesigns, which can be effective at eliminating the common root cause. However, design changes usually take more time than procedural changes due to the requirements for verification testing and component changeout. The benefit of these design changes can take years to be fully effective as equipment owners may decide to delay changing out a component that has not yet failed. The delay could be to allow the new design to be proven elsewhere or simply to wait until the scheduled maintenance becomes due.

Nickel leaching from the use of demineralized water in BOP control fluid systems remained an issue in 2020, as described in Table 16 (see lines 28 and 29). Most of these failures cited procedural error as the root cause and listed adding remineralizers to the water supplied to the BOP fluid mix system as a preventive action.

Chapter 3: Surface WCE System Events

A surface WCE system includes a BOP located above the water on the rig and associated equipment such as BOP controls, BOP stack, riser system, diverter, choke manifold, and auxiliary equipment. Table 17 lists measures related to all GOM OCS surface wells undergoing activity, together with event data, during each of the last four years. In total, 21 surface system events were reported to SafeOCS in 2020, compared to 87 in 2019, representing a 75.9 percent decrease. There were an additional 42 surface system events identified in WAR; however, limited data was available to categorize these failures beyond a count. When adjusted for well activity, reported surface system events declined 56.6 percent, from 12.2 events per thousand BOP days in 2019 to 5.3 in 2020. As in previous years, events were relatively evenly split between operational states, with nine events detected while in operation and 12 while not in operation. Due to greater accessibility of equipment, components are often not changed out until an issue occurs, even if

Table 17: Surface System Numbers at a Glance, 2017-2020

MEASURE	2017	2018	2019	2020
WELLS				
Wells with Activity	160	217	208	122
Wells Spudded	65	86	86	41
RIGS				
Rigs with Activity	28	28	34	24
Rigs with Reported Events	19	16	15	10
OPERATORS				
Active Operators	19	24	21	17
Reporting Operators	11	8	9	8
BOP DAYS				
Total BOP Days	5,172	6,938	7,107	3,960
In-Operation BOP Days	3,615	5,067	5,243	2,734
Not-in-Operation BOP Days	1,557	1,871	1,864	1,226
COMPONENT EVENTS				
Total Events Reported*	115	69	87	21
Overall Event Rate	22.2	9.9	12.2	5.3
In-Operation Events	58	35	44	9
In-Operation Event Rate	16.0	6.9	8.4	3.3
In-Operation Events per Well	0.4	0.2	0.2	0.1
Not-in-Operation Events	57	34	43	12
Not-in-Operation Event Rate	36.6	18.2	23.1	9.8
Not-in-Operation Events per Well	0.4	0.2	0.2	0.1
BOP STACK MOVEMENTS				
Total Stack Starts	186	224	225	133
Successful Starts	170	217	199	112
Stack Pulls	10	10	36**	9**
LOC EVENTS				
Loss of Containment Events	0	0	0	0

KEY: In-operation Not-in-operation

NOTES:

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

** Includes stack pulls identified in WAR data (16 in 2019 and 6 in 2020).

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

that is during operations. This results in the higher percentage of failures seen in-operation as compared to subsea systems.

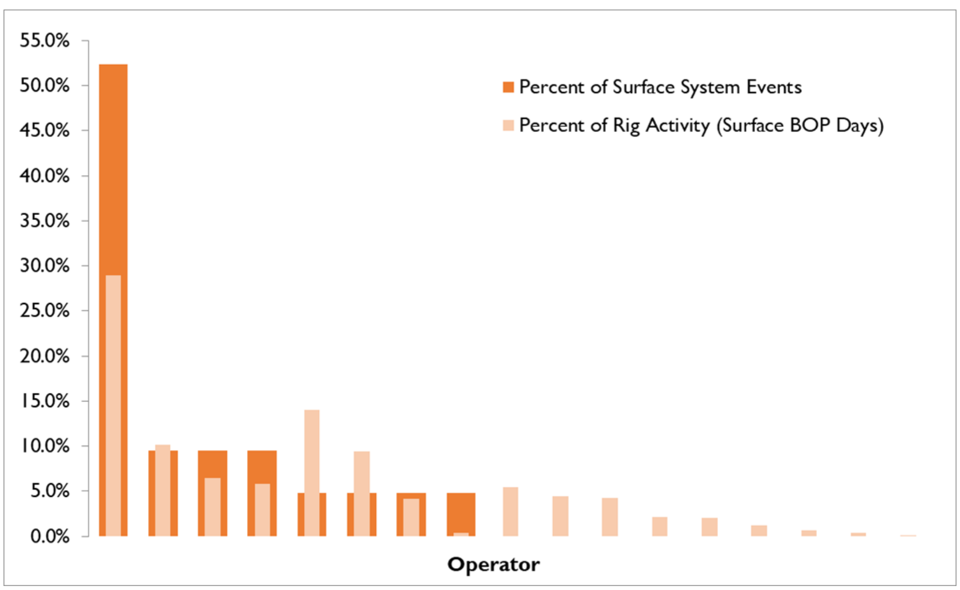
Table 17 shows that from 2019 to 2020, there were 41.3 percent fewer wells with activity and 44.3 percent fewer BOP days, with a fleet 10 rigs smaller. Surface system rigs conducted well operations on nearly as many wells as subsea system rigs, at an average of 5.1 wells per rig compared to an average of 5.5 wells per subsea system rig (see Table 2).

Considering both stack pulls reported to SafeOCS and those identified in WAR data, nine total stack pulls were recorded in 2020, compared to 36 in 2019. About 8.0 percent (nine of 112) of successful surface BOP stack starts—meaning the stack was assembled on the wellhead and went into operation—eventually led to a stack pull in 2020. This represents an improvement from 18.1 percent in 2019.

Reporting Operators

Figure 7 shows surface system events and rig activity (measured in BOP days) for the 17 active operators with surface system well operations in 2020. The eight reporting operators represented 47.1 percent of active operators and accounted for 79.5 percent of surface BOP days. Overall, reporting levels for surface systems continue to remain below 50.0 percent of active operators and active rigs.

Figure 7: Surface System Events and Rig Activity by Operator, 2020



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

Events by Subunit

Table 18 and Table 19 show that, in general, the subunits with the most components carry the greatest numbers of events, with most events from 2017 to 2019 attributed to the BOP control, BOP stack, or choke manifold systems. The same is generally true for events in 2020, although there were relatively few events.

Table 18: Not-In-Operation Events by Subunit (Surface Systems), 2017-2020

SUBUNIT	2017-19 (n=134)	2020 (n=12)
BOP CONTROL SUBUNITS		
BOP Primary Control System	29.1%	58.3%
OTHER SUBUNITS		
Auxiliary Equipment	4.5%	0.0%
BOP Stack System	50.0%	25.0%
Choke Manifold System	13.4%	16.7%
Diverter System	0.0%	0.0%
Riser System	3.0%	0.0%

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

Table 19: In-Operation Events by Subunit (Surface Systems), 2017-2020

SUBUNIT	2017-19 (n=137)	2020 (n=9)
BOP CONTROL SUBUNITS		
BOP Primary Control System	35.0%	66.7%
OTHER SUBUNITS		
Auxiliary Equipment	5.8%	0.0%
BOP Stack System	40.1%	22.2%
Choke Manifold System	18.2%	0.0%
Diverter System	0.0%	11.1%
Riser System	0.7%	0.0%

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

Events by Failure Type

As shown in Table 20 and Table 21, most events (75.0 percent of not-in-operation events and 77.8 percent of in-operation events) in 2020 were either an external or internal leak, similar to previous years. 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 in 2020 were leaks of wellbore fluids (i.e., losses of containment).

Table 20: Types of Not-In-Operation Events (Surface Systems), 2017-2020

EVENT TYPE	2017-19 (n=134)	2020 (n=12)
LEAKS		
External Leak	38.8%	66.7%
Internal Leak	44.8%	8.3%
OTHER		
Communication / Signal Issue	0.7%	0.0%
Electrical Issue	1.5%	8.3%
Fail to Function on Command	3.0%	0.0%
Inaccurate Indication	0.7%	0.0%
Mechanical Issue	7.5%	16.7%
Process Issue	3.0%	0.0%
Unintended Operation	0.0%	0.0%

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

Table 21: Types of In-Operation Events (Surface Systems), 2017-2020

EVENT TYPE	2017-19 (n=137)	2020 (n=9)
LEAKS		
External Leak	28.5%	55.6%
Internal Leak	50.4%	22.2%
OTHER		
Communication / Signal Issue	3.6%	0.0%
Electrical Issue	0.0%	0.0%
Fail to Function on Command	2.9%	11.1%
Inaccurate Indication	0.0%	0.0%
Mechanical Issue	10.2%	0.0%
Process Issue	4.4%	0.0%
Unintended Operation	0.0%	11.1%

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

Detection Methods

More than half of surface system events from 2017 to 2019 were detected through pressure or function testing, as shown in Table 22 and Table 23. In 2020, MIT detection methods accounted for 50.0 percent of not-in-operation events and 66.6 percent of in-operation events.

Table 22: Detection Methods for Not-In-Operation Events (Surface Systems), 2017-2020

	DETECTION METHOD	2017-19 (n=134)	2020 (n=12)
	Casual Observation	6.7%	33.3%
	Continuous Condition Monitoring	3.7%	8.3%
	On Demand	0.0%	0.0%
	Periodic Condition Monitoring	0.7%	8.3%
MIT	Corrective Maintenance	1.5%	0.0%
MIT	Periodic Maintenance	3.0%	16.7%
MIT	Inspection	10.4%	0.0%
MIT	Function Testing	17.2%	25.0%
MIT	Pressure Testing	56.7%	8.3%

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

Table 23: Detection Methods for In-Operation Events (Surface Systems), 2017-2020

	DETECTION METHOD	2017-19 (n=137)	2020 (n=9)
	Casual Observation	13.9%	33.3%
	Continuous Condition Monitoring	10.9%	0.0%
	On Demand	1.5%	0.0%
	Periodic Condition Monitoring	1.5%	0.0%
MIT	Corrective Maintenance	2.2%	0.0%
MIT	Periodic Maintenance	0.0%	0.0%
MIT	Inspection	8.0%	22.2%
MIT	Function Testing	11.7%	22.2%
MIT	Pressure Testing	50.4%	22.2%

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

Root Causes of Events

Table 24 and Table 25 show the distribution of root causes for surface system events. As in past years, wear and tear has remained the most frequent root cause of events, reported for 19 events in 2020. For the remaining two events that fell under *other*, the provided root cause was a description of what the reporter found, such as a damaged o-ring.

Table 24: Root Causes of Not-In-Operation Events (Surface Systems), 2017-2020

ROOT CAUSE	2017-19 (n=134)	2020 (n=12)
Design Issue	3.0%	0.0%
QA/QC Manufacturing	6.0%	0.0%
Maintenance Error	13.4%	0.0%
Procedural Error	4.5%	0.0%
Wear and Tear	40.3%	83.3%
Other	8.2%	16.7%
NOT DETERMINED		
Inconclusive	2.2%	0.0%
Assessment Pending	4.5%	0.0%
Not Reported	17.9%	0.0%

KEY: Not-in-operation
NOTE: Most of the events without a root cause in 2017-19 occurred in 2017 and were reported via an early data collection form that did not request information on root causes.
SOURCE: U.S. DOT, BTS, SafeOCS program.

Table 25: Root Causes of In-Operation Events (Surface Systems), 2017-2020

ROOT CAUSE	2017-19 (n=137)	2020 (n=9)
Design Issue	5.1%	0.0%
QA/QC Manufacturing	2.9%	0.0%
Maintenance Error	1.5%	0.0%
Procedural Error	0.0%	0.0%
Wear and Tear	59.9%	100.0%
Other	6.6%	0.0%
NOT DETERMINED		
Inconclusive	0.7%	0.0%
Assessment Pending	5.8%	0.0%
Not Reported	17.5%	0.0%

KEY: In-operation
NOTE: Most of the events without a root cause in 2017-19 occurred in 2017 and were reported via an early data collection form that did not request information on root causes.
SOURCE: U.S. DOT, BTS, SafeOCS program.

Stack Pull Events

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.[19] However, the data review indicates that some events that should have been reported as a stack

[19] 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.

pull were not, either because 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.

In 2020, three stack pulls were reported to SafeOCS and an additional six stack pulls were identified in WAR data, for a total of nine surface stack pulls. Table 26 shows that as in previous years, most surface stack pulls in 2020 were for internal leaks.

Root Causes of Surface Stack Pulls

Table 27 shows the distribution of root causes for events leading to surface stack pulls. As in previous years, wear and tear was the most common root cause, attributed to all three surface stack pull events reported to SafeOCS. For the six stack pulls identified in WAR, no definitive root cause was listed.

Component Combinations Associated with Surface Stack Pulls

Table 28 shows the components and event types for events leading to surface stack pulls from 2017 to 2020. The similarities in the numbers of total in-operation events as compared to stack pulls for these component combinations means that the failed component

Table 26: Types of Events Leading to Surface Stack Pulls, 2017-2020

EVENT TYPE	2017-19	2020
LEAKS		
External Leak	9	3
Internal Leak	43	5
OTHER		
Communication / Signal Issue	1	-
Fail to Function on Command	2	-
Mechanical Issue	1	-
Process Issue	-	-
Unintended Operation	-	1
TOTAL	**56***	**9***

KEY: In-operation
NOTES:
* 2019 includes 16 stack pulls identified in WAR, and 2020 includes six stack pulls 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 27: Root Causes of Surface Stack Pulls, 2017-2020

ROOT CAUSE	2017-19	2020
Design Issue	3	-
QA/QC Manufacturing	1	-
Maintenance Error	1	-
Wear and Tear	23	3
Other	3	-
NOT DETERMINED		
Inconclusive	1	-
Assessment Pending	2	-
Not Reported	6	-
Unknown to SafeOCS*	16	6
TOTAL	**56**	**9**

KEY: In-operation
NOTES:
* The root causes of 16 stack pulls in 2019 and six stack pulls in 2020 identified in WAR are unknown to SafeOCS.
- Dash indicates a count of zero.

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

had no redundancy and therefore needed to be repaired or replaced.

Almost half of surface stack pulls in 2020 were due to the annular packing elements failing to hold pressure (i.e., some level of internal leak across the packing element), similar to 2019, where the majority of stack pulls were due to the same issue. 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. This is typical practice for surface systems where there is easier access to equipment. Further details and summaries of the 2020 surface stack pull events can be found in Appendix D.

Table 28: Equipment and Types of Failures Associated with Surface Stack Pulls, 2017-2020

Item	Component	Failure Type	2017-2020		2020 Only	
			In-Operation Events	Stack Pulls	In-Operation Events	Stack Pulls
Annular Preventer	Hardware_all other Mech.	External Leak	1	1	-	-
	Operating System Seal	Internal Leak	4	4	-	-
	Packing Element	Fail to Function on Command	2	2	-	-
		Internal Leak	36	32	4	4
BOP Control Panel	Central Control Console	Communication / Signal Issue	2	1	-	-
	Instrumentation	Mechanical Issue	1	1	-	-
HPU Mix System	Regulator	External Leak	1	1	-	-
	Selector Manipulator Valve	External Leak	2	2	2	2
Pipe Ram Preventer	Ram Block Seal	Internal Leak	4	3	-	-
	Bonnet Face Seal	External Leak	1	1	1	1
	Bonnet Seal	External Leak	1	1	-	-
Shear Ram Preventer	Bonnet Face Seal	External Leak	3	3	-	-
	Bonnet Operating Seal	Internal Leak	2	2	-	-
	Ram Block Seal	Internal Leak	7	7	1	1
	Unknown	Unintended Operation	1	1	1	1
Surface Control System	Regulator	External Leak	5	2	-	-
Total			**73**	**64**	**9**	**9**

NOTE: Each of the stack pulls identified only in WAR (16 in 2019 and six in 2020) are included in this table as both a stack pull and an in-operation event. Dash indicates a count of zero.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Investigation and Analysis

I&A information was received for seven of the 21 surface system events in 2020. Of the seven I&As pertaining to these events, one contained preventive actions, and the cause was immediately known. Table 29 summarizes the findings for this I&A, which was for a failure that occurred while not-in-operation during a hurricane evacuation.

Table 29: Findings from I&As for Surface System Events, 2020

ROOT CAUSE	ROOT CAUSE DETAILS	RECOMMENDED PREVENTIVE ACTION	2020 Events
Wear and Tear	The armor coating on a choke hose was damaged during a hurricane event after 17 months of use. The hose had not been properly secured prior to rig evacuation.	Equipment owner to implement a procedure to better secure the hose during future hurricane evacuation.	1

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

CHAPTER 4: CONCLUSION AND NEXT STEPS

Key findings from this report include the following:

- The coronavirus pandemic was likely a significant factor in the overall decrease in drilling activity levels in 2020. The number of wells with activity declined by about a third and drilling hours worked dropped by nearly a quarter.
- For both subsea and surface WCE systems, reported events, adjusted based on the amount of well activity, decreased in 2020 as compared to 2019 and showed an overall decrease since 2017.
- Overall, 83.0 percent of known WCE events in 2020 were reported to SafeOCS, with the remainder identified in WAR data. This apparent underreporting tended to be higher for surface systems, with 21 of 63 known events reported to SafeOCS. Although both surface system rigs and subsea system rigs conducted well operations on a similar average number of wells per year in 2020, only 21 event notifications were submitted to SafeOCS for surface systems, compared to 608 for subsea systems.
- 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, consistent with previous years' reporting. This aligns with the rigorous MIT protocols carried out for these systems between well operations.
- A time-to-failure analysis for subsea system events from 2017 to 2020 provided an overview of the distribution of time to failure for commonly reported component failures and for components associated with a stack pull. This framework could serve as a basis for component-level analysis of changes in average time to failure from year to year.
- No leaks of wellbore fluids to the environment, classified as losses of containment, were reported to SafeOCS in 2020, and only one such event has been reported since the data collection began in mid-2016.

Next Steps: Opportunities for Improving Data Quality

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

- Continue efforts to revise the data collection form and guidance to improve data quality, with input from the BOP reliability JIP. 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 and equipment usage information better.
    - Revise event type categories to improve consistency across component types.
    - Streamline detection method selections.
    - Consider improvements for capture of reoccurring failures.
- Develop a framework for aggregation and analysis of intervention and workover events, including revisions to the form to support improved capture of intervention equipment details.
- Work with stakeholders to improve the data collection process by:
    - Identifying opportunities to improve reporting of specific root cause failure analysis results and learnings that may have industry-wide benefit.
    - Promote coverage, completeness, accuracy, and timeliness of data collected.

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.[20] The rule follows ("you" refers to lessees and designated operators):

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

[20] 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.

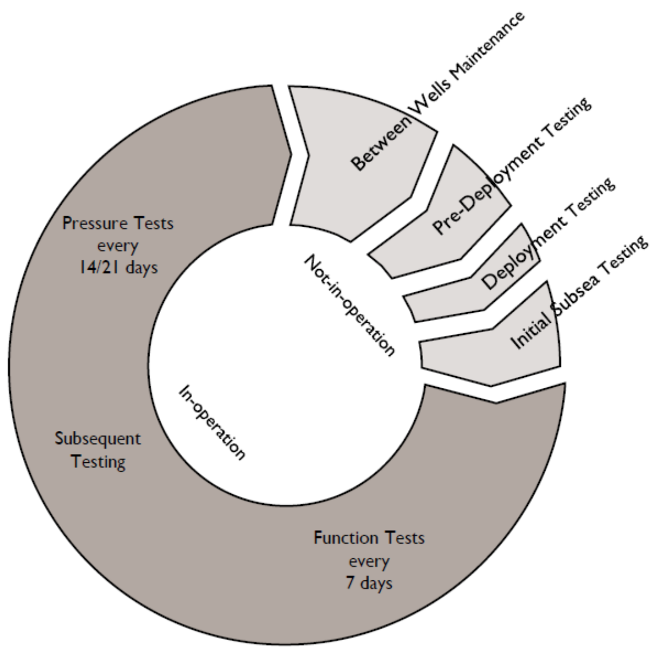
(4) Submit notices and reports to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, Virginia 20166. BSEE may designate a third party to receive the data and reports on behalf of BSEE. If BSEE designates a third party, you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

APPENDIX B: OPERATIONAL STATES OF WCE SYSTEMS

This appendix separates events into two states, where applicable, based on when the event occurred: *in-operation* or *not-in-operation*. This section provides an overview of these states and the various phases within them to provide additional context for failure events. Figure 8 provides a visual representation for subsea WCE systems.

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

Figure 8: The Cycle of Maintenance, Inspection, and Testing



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

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

API Standard 53.[21] The remainder of this section includes a discussion of time-based versus condition-based maintenance practices, followed by more detail about each phase of MIT.

Condition-Based Maintenance

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

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

MIT for Subsea WCE Systems

MIT While Not in Operation

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

---

[21] 30 CFR 250.737, 250.739.

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

- **Pre-Deployment Testing:** This is the minimum required testing that must be carried out before the WCE systems can be deployed subsea. It takes place on the rig before the 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 the discussion of the riser system in the SafeOCS supplement, *WCE Subunit Boundaries*, published separately.

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

MIT During Operations: Subsequent Testing

Subsequent testing regimes take place while the BOP stack is in operation. Every seven days,[22] all the non-latching equipment[23] 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,[24] all pipe rams, annulars, valves, and the choke manifold are pressure tested. Every 21 days, the acoustic batteries are checked,[25] and the shear rams are pressure-tested.[26] 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.[27] If the BOP stack is not subsea long enough for these tests to become due, then the pre-deployment testing for the next well will include them.

MIT for Surface WCE Systems

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

MIT While Not in Operation

Many surface BOPs are rented and maintained by third parties or maintained by the equipment owner at shore bases. When the well operation ends, and BWM is required, the equipment is often sent to shore for maintenance and exchange. Importantly, failure events identified

[22] 30 CFR 250.737 and API Standard 53 (4th ed.) section 7.6.5.1.1.
[23] 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.
[24] 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).
[25] API Standard 53 (4th ed.) table 7.
[26] Shear rams are pressure tested at least every 30 days per 30 CFR 250.737(a)(2). Operators may also follow the more frequent 21-day testing per API Standard 53 (4th ed.) table 10.
[27] API Standard 53 (4th ed.) table 7.

onshore by third parties while the equipment is not under contract to the operator may be less likely to be reported to SafeOCS.

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

MIT During Operations: Subsequent Testing

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

APPENDIX C: 2020 COMPONENT POPULATION ESTIMATES

The following tables provide estimates of the total population of components for active rigs in 2020. The details of these estimates are provided in the SafeOCS supplement, *WCE Estimated System Component Counts*, published separately.

Table 30: Estimates of Subsea WCE Components by Subunit, 2020

SUBUNIT	ONE-STACK SYSTEM		TWO-STACK SYSTEM		Total
	Components	Active Rigs	Components	Active Rigs	Components
BOP CONTROL SUBUNITS					
BOP Primary Control System	1,111	6	1,979	20	46,246
BOP Emergency Control System	139	6	276	20	6,354
BOP Secondary Control System	132	6	240	20	5,592
OTHER SUBUNITS					
Auxiliary Equipment	41	6	43	20	1,106
BOP Stack System	380	6	760	20	17,480
Choke Manifold System	369	6	369	20	9,594
Diverter System	96	6	96	20	2,496
Riser System	786	6	786	20	20,436
TOTAL	3,054		4,549		109,304

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

Table 31: Estimates of Surface WCE Components by Subunit, 2020

SUBUNIT	Components	Active Rigs	Total Components
BOP CONTROL SUBUNITS			
BOP Primary Control System	143	24	3,432
OTHER SUBUNITS			
Auxiliary Equipment	35	24	840
BOP Stack System	125	24	3,000
Choke Manifold System	369	24	8,856
Diverter System	95	24	2,280
Riser System*	0	24	0
TOTAL	767		18,408

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.

APPENDIX D: 2020 STACK PULL EVENT SUMMARIES

Table 32: Subsea Stack Pull Summaries, 2020

SUBUNIT	ITEM	COMPONENT	FAILURE TYPE	DESCRIPTION	DETECTION METHOD	ROOT CAUSE
BOP Controls	BOP Control Pod	Check Valve	External Leak	ROV observed a leak originating from a pod pilot supply check valve.	Inspection	Wear and Tear
BOP Controls	BOP Control Pod	Gas Valve	External Leak	During inspection accumulators found to be leaking nitrogen from the gas valves.	Functional Testing in Operation	Wear and Tear
BOP Controls	BOP Controls Stack Mounted	Piping/Tubing	External Leak	Loose fitting on a stack kill valve control circuit.	Inspection	Procedural Error
BOP Controls Emergency Automated Functions	Autoshear Deadman EHBS	SPM Valve	External Leak	ROV observed leak from SPM valve cap.	Inspection	Assessment Pending
BOP Stack	Annular Preventer	Packing Element	Fail to Function on Command	Packing assembly on the lower annular split, preventing it from fully opening.	On Demand	Design Issue
BOP Stack	Annular Preventer	Packing Element	Internal Leak	Leak discovered while attempted to test low pressure on the lower annular.	Pressure Testing in Operation	Unknown to SafeOCS*
BOP Stack	Shear Ram Preventer	Bonnet Operating Seal	Internal Leak	Pulled BOP to troubleshoot upper blind shear ram closed hydraulic leak.	Unknown to SafeOCS*	Unknown to SafeOCS*
BOP Stack	Stack Choke and Kill System	Flex Loop Hose	External Leak	External leak observed during high pressure testing of the upper annular. ROV visually verified dye leak on LMRP kill line jumper hose.	Pressure Testing in Operation	Unknown to SafeOCS*

NOTE: *Event identified in WAR data, which has limited event details.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Table 33: Surface Stack Pull Summaries, 2020

SUBUNIT	ITEM	COMPONENT	FAILURE TYPE	DESCRIPTION	DETECTION METHOD	ROOT CAUSE
BOP Controls	HPU Mix System	Selector Manipulator Valve	Internal Leak	Noticed a very slight internal leak on the annular control selector valve. Although the annular was still fully functional, the well was secured, and the valve seals were changed.	Inspection	Wear and Tear
BOP Controls	HPU Mix System	Selector Manipulator Valve	Internal Leak	Noticed four-way valve for annular leaking while doing daily checks. Immediately shut the well in and changed out internal parts of the valve.	Inspection	Wear and Tear
BOP Stack	Annular Preventer	Packing Element	Internal Leak	Damage noticed during visual inspection of the packer while the stack was empty. Unsuccessfully attempted a pressure test. Replaced packer while monitoring well on the trip tank.	Pressure Testing in Operation	Wear and Tear
BOP Stack	Annular Preventer	Packing Element	Internal Leak	Annular would not test.	Pressure Testing in Operation	Unknown to SafeOCS*
BOP Stack	Annular Preventer	Packing Element	Internal Leak	Changed out annular element.	Pressure Testing in Operation	Unknown to SafeOCS*
BOP Stack	Annular Preventer	Packing Element	Internal Leak	Annular failed pressure test on 2-3/8" pipe during testing conducted after an evacuation. Annular element was replaced.	Pressure Testing in Operation	Unknown to SafeOCS*
BOP Stack	Pipe Ram Preventer	Bonnet Face Seal	External Leak	Performed repairs for leaks on kill line side HCR valve and bonnet seals for upper pipe rams found leaking during BOP pressure testing.	Pressure Testing in Operation	Unknown to SafeOCS*
BOP Stack	Shear Ram Preventer	Ram Block Seal	Internal Leak	Blind shear ram failed high pressure test after multiple attempts. Changed out shear rams.	Pressure Testing in Operation	Unknown to SafeOCS*
BOP Stack	Shear Ram Preventer	Unknown to SafeOCS*	Unintended Operation	While functioning BOPs from alternate stations the blind shear rams were closed, and the drill pipe was cut.	Unknown to SafeOCS*	Unknown to SafeOCS*

NOTE: *Event identified in WAR data, which has limited event details.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

APPENDIX E: GLOSSARY

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

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

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

Blind Shear Ram: A closing and sealing component in a ram blowout preventer 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 well can experience a blowout when the formation's pressure is higher than the fluid's hydrostatic pressure.

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

BOP Control Fluid: A term commonly used for both the 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: The number of days during which some or all the WCE components may have been in use and had any likelihood of a failure. Additional information is provided under *Data Validation and Exposure Measures*, page 4.

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.

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

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

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.

Dry Fire Testing: The emergency disconnect sequence (EDS) allows several control system options (or modes) for closing the shear rams to secure the well. To test the shear rams without unnecessary wear to their seals, it is common to "dry fire" some EDS modes, which means that the operating fluid supply is isolated with only the control valves monitored for operation, and the mode that consumes that largest volume of hydraulic fluid is tested by activation. This ensures that all the relevant control valves are tested and also proves that there is sufficient stored hydraulic pressure to activate any of the modes. There should not be any intent to physically lift the LMRP from the lower stack after a dry fire, as this can cause equipment damage. Rather, this should be reserved for and demonstrated after every wet fire.

Emergency Disconnect Sequence (EDS): Per API Standard 53, an EDS is required on all subsea BOP stacks that are run from a dynamically positioned vessel. It is a programmed sequence of events that operates the functions to leave the stack and controls in a desired state and disconnect the LMRP from the lower stack. The number of sequences, timing, and functions of the EDS are specific to the rig, equipment, and location. All assigned components are to be function tested on surface prior to deployment, must be tested subsea at commissioning or within five-years of the previous test, and must secure the well in 90 seconds or less.

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 Operations: Well operations including, for example, 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 referenced period.

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

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

Subunit: See Well Control Equipment Subunits.

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

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

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

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

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

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

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

Detection Method Terms

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

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

Corrective Maintenance: Unscheduled maintenance or repairs.

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

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

On-demand: Inability to function when required.

Periodic Condition Monitoring: Regular checks.

Periodic Maintenance: Planned, scheduled maintenance routine.

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

Appendix F: Acronyms

ANSI: American National Standards Institute

API: American Petroleum Institute

BOP: Blowout preventer

BSEE: Bureau of Safety and Environmental Enforcement

BSR: Blind shear ram

BTS: Bureau of Transportation Statistics

CFR: Code of Federal Regulations

C/K: Choke/kill

CIPSEA: Confidential Information Protection and Statistical Efficiency Act

D&I: Disassembly and inspection

DOI: Department of the Interior

DOT: Department of Transportation

EHBS: Emergency hydraulic backup system

GOM: Gulf of Mexico

HPU: Hydraulic power unit

IADC: International Association of Drilling Contractors

IOGP: International Association of Oil and Gas Producers

I&A: Investigation and failure analysis

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

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

SPM: Sub-plate mounted

WAR: Well activity report (per 30 CFR 250.743)

WCE: Well control equipment

WCR: Well Control Rule