Blowout Prevention System Safety Events

2018 Annual Report

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2018 Annual Report

BLOWOUT PREVENTION SYSTEM SAFETY EVENTS

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Table of Contents

LIST OF FIGURES

LIST OF TABLES

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Executive Summary

The 2018 Annual Report: Blowout Prevention System Safety summarizes blowout prevention (BOP) equipment failures that occurred during drilling and non-drilling rig operations in the Gulf of Mexico (GOM) Outer Continental Shelf (OCS). It includes analyses of the types of equipment component failures reported and key information about them, such as root causes and follow-up actions. The report also discusses opportunities to improve data quality and accessibility.

This report is based on data from 1,196 failure notifications submitted to SafeOCS in 2018, the second full year of well control equipment component failure reporting, as well as aggregated data collected since the program's start in July 2016. Overall, the amount of rig activity in the GOM increased, while reporting activity decreased from 2017 to 2018. The number of wells spud, total wells with activity, number of active operators, and number of BOP days[1] increased. However, the number of operators reporting failure events, the number of rigs involved in those events, and the number of reported events decreased.

In 2018, 14 of 32 operators associated with rig operations in the GOM reported equipment component failure events. Reporting operators accounted for 82.1 percent of wells spudded and 85.3 percent of drilling activity. The reported events occurred on 40 of the 59 rigs operating in the GOM during this period. Nearly 95 percent of reported events (1,127 of 1,196) pertained to subsea BOP systems, as opposed to surface BOP systems.

Other observations and findings include the following:

- There were no reported loss of containment (LOC) events in 2018.
- The four operators that reported the most failures represented 89.0 percent of component events and 47.3 percent of rig activity (measured in BOP days) in the GOM in 2018.
- Leaks remained the most frequently reported observed failure, and wear and tear remained the most frequently reported root cause of failure events in 2018.
- While the rate of stack pulls has fluctuated from year to year for both subsea and surface systems, completion of root cause failure analyses (RCFAs) for stack pulls has remained under 50.0 percent, despite the requirement of an RCFA for every stack pull.

[1] See Appendix C for definition.

- Overall, the percent of events with additional information submitted on causal factors via an investigation and failure analysis has decreased each year.
- For events on subsea BOP systems, the percent of reported not-in-operation events has steadily increased each year since 2016.
- For events on surface BOP systems, the percent of reported not-in-operation events has remained approximately 50.0 percent across the reporting period.

Collecting more detailed, accurate, relevant, and timely equipment failure data can support more in-depth statistical analyses to inform industry safety improvement efforts. SafeOCS continues to focus on improvement efforts for data collection, processing, harmonization, and accessibility.

Introduction

The 2018 Annual Report: Blowout Prevention System Safety provides information on well control equipment component failures reported to SafeOCS during the calendar year. These failures occurred during drilling and non-drilling rig 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 overview of the types of failures reported, analysis of root causes, and a summary of reported lessons learned from failure event investigations. It also discusses opportunities to improve data quality and accessibility.

About SafeOCS

The Department of Transportation's Bureau of Transportation Statistics (BTS), a principal federal statistical agency, entered an interagency agreement with the Department of the Interior's Bureau of Safety and Environmental Enforcement (BSEE) to develop, implement, and operate the SafeOCS program. SafeOCS is a confidential reporting program that collects and analyzes data to advance safety in oil and gas operations on the OCS. The objective of SafeOCS is to capture and share essential information across the industry about accident precursors and potential hazards associated with offshore operations. The Confidential Information Protection and Statistical Efficiency Act of 2002 (CIPSEA) protects the confidentiality of all data submitted directly to SafeOCS.[2]

Collaboration

This report is the product of wide-ranging collaboration between key stakeholders in the oil and gas industry and government.

- **The Joint Industry Project (JIP) on BOP Reliability Data**: In early 2016, the International Association of Drilling Contractors (IADC) and the International Association of Oil and Gas Producers (IOGP) created a joint industry project (JIP) to develop a blowout preventer (BOP) reliability database, building on prior industry efforts. BTS collaborated extensively with the JIP in the deployment of SafeOCS in 2016, specifically in the design of the data collection system and supporting documentation. The SafeOCS program continues to receive input from the JIP.
- **Internal SME Review Team**: SafeOCS retained subject matter experts (SMEs) in drilling operations; production operations; subsea engineering; equipment testing; and well control

[2] For more information on CIPSEA, refer to Appendix B.

equipment design and manufacturing, including BOPs, root cause failure analysis, quality assurance, quality control, and process design. The SMEs reviewed notifications to assess accuracy and consistency. They helped to validate and clarify BTS and BSEE data and provided input to this report.

- **BSEE**: BSEE provided BTS with well activity reports, population and exposure data on production levels, rig activity, and ranges and types of facilities and structures. BSEE-provided data was used for data validation, benchmarking, and development of exposure measures, described below.

On Estimating Exposure Measures for Equipment and Activity Levels

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

Exposure Measures from BSEE Well Activity Reports (WARs)

Well activity reporting in the GOM, Pacific, and Alaska OCS regions is required daily or weekly (depending on the region), per 30 CFR 250.743. Well activity includes drilling and non-drilling operations such as pre-spud operations,[3] drilling, workover operations, well completions, tie-back operations, recompletions, zone change, modified perforations, well sidetracking, well suspension, temporary abandonment, and permanent abandonment. Operators must submit WARs for well operations performed by all drilling rigs, snubbing units, wireline units, coil tubing units, hydraulic workover units, non-rig plug and abandonment operations, and lift boats.

SafeOCS staff and SMEs review WAR data to provide context for the equipment component failures reported to SafeOCS. As in previous reports, only WARs for rigs are analyzed regardless of the well operation performed.[4] Measures currently analyzed from WARs include:

- **Wells with Activity:** The number of wells worked on by rigs.
- **Rigs with Activity:** The number of rigs with operations.
- **Active Operators:** The number of operators conducting rig operations.

[3] The period preceding the start of drilling activities (Appendix C).

[4] Failure reports involving non-rigs are excluded from this annual report, therefore non-rig WARs were also excluded.

- **Rig hours/days:** The hours/days rigs were active. This measure approximates the amount of time during which an equipment component failure could have occurred within a given period.
- **BOP hours/days:** The hours/days a BOP and related well control equipment was exposed to the opportunity for an equipment failure within a given period. For rigs with one BOP, this is equivalent to their calculated number of rig hours/days. For rigs with two BOPs, their calculated rig hours/days is multiplied by 1.45, based on the determination that having two BOPs is approximately equivalent to having 1.45 times the number of components as having one BOP.[5]
  - **In-operation BOP hours/days:** The hours/days a BOP and related well control equipment had the opportunity for an in-operation equipment failure or stack pull within a given period. This number is a subset of BOP hours/days.
- **BOP stack runs:** The number of times a subsea BOP stack was run from the rig floor (or other areas at the base of the rig such as the "moonpool") to the wellhead during a given period. This number also includes when the stack was being moved from one location to another while staying submerged. This measure applies to subsea stacks only, as surface stacks are not "run" or "deployed" to the wellhead.
- **BOP stack starts:** The number of times a surface BOP stack was assembled on the wellhead and went into operation. This is referred to in the industry as "rigging up" the BOP. This measure applies to surface stacks only.
- **BOP latches and unlatches:** The number of times a BOP stack was latched or unlatched from a wellhead during a given period.

Exposure Measure from BSEE Boreholes Data

Wells spud data from the BSEE boreholes table provides information on the number of newly "spudded" wells within a given time frame, providing context for the scope of rig operations in the GOM OCS in 2018. SafeOCS analyzes this data to provide context on the scope of new activity (new wells spudded) in a given year.

Report Structure

The first section of the 2018 Annual Report, Numbers at a Glance, contains summary statistics and exposure measures about the reported equipment component failures. The 2018 report presents data by BOP system type – subsea and surface offshore – facilitating a more in-depth analysis of each BOP

[5] For purposes of this report, a one-BOP subsea system is estimated to have ≅ 5,000 components, whereas a two-BOP subsea stack system has ≅ 7,200 components. Counts are general estimates for typical subsea systems; exact counts vary by operator, rig, and individual BOP stack configurations.

system's unique characteristics and the effect on equipment component events. Four significant factors support organizing the report by BOP system type:

1. **Complexity:** Subsea BOP systems have a higher number of components than surface BOP systems.
2. **Accessibility of Equipment:** Most subsea equipment is located 5,000 or more feet below sea-level and requires a remotely operated vehicle (ROV) to view and access; whereas, almost all surface system equipment is on deck, visible, and accessible at all times.[6]
3. **Environmental Impact:** Water-based fluid almost always powers subsea BOP control systems; hydraulic oil typically powers surface BOP control systems. Therefore, the potential consequences of a leak from a surface BOP control system are more significant than from a subsea BOP control system.[7]
4. **Management of Equipment:** Rigs with subsea BOPs have a full-time crew of subsea engineers that operate and maintain equipment. Rigs with surface offshore BOPs generally have a crew of drillers and mechanics that split oversight duties and responsibility for operating and maintaining the equipment.

These factors lead to different operational practices for subsea systems compared to surface systems, such as more time spent during inspections, maintenance, and testing, which result in varied reporting requirements and outcomes. They also result in diverse methods for conducting investigations and failure analyses. Within Chapter 2: Events on Subsea BOP Systems and Chapter 3: Events on Surface BOP Systems, event data are presented by when the event occurred (while not in operation or in operation) and the percentage of events that led to stack pulls. Investigation and failure analysis results are also presented separately by type of system.

Appendix C contains a glossary with detailed definitions of technical terms. Within the text of this report, glossary terms and terms used in the data collection form may be italicized on first use or for clarity.

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[6] As an example, more time is spent inspecting, maintaining, and testing specific equipment (such as ram and annular packers) before deployment for subsea stacks, since a failed component might require retrieval of the subsea stack to repair the component. The same equipment on a surface stack would not need as much time to replace, since the stack does not need to be retrieved.

[7] Note, however, that wellbore fluid leaks from either subsea or surface systems pose potential environmental impacts.

Analysis Information and Data Adjustments

Due to rounding, numbers in tables and figures may not add up to totals. References to the term *subsea* and the term *surface* are related to the type of BOP system on which an event occurred, not the event's location in relation to the waterline. BTS received a significant number of 2017 well control equipment component failure notifications after the publication of the 2017 Annual Report. All reported results and references to 2017 data in this report encompass updated numbers unless otherwise stated.

CHAPTER 1: NUMBERS AT A GLANCE

For 2018, SafeOCS received equipment failure notifications from one region, the GOM OCS, which accounts for over 99 percent of annual oil and gas production on the OCS. There were 389 active wells in the GOM OCS in 2018: 190 wells were newly spudded, and 199 were active since the previous year. There were 32 operators actively involved in drilling and non-drilling activities on those wells, and of those, 14 operators submitted equipment failure notifications. The reported events occurred on 40 of the 59 rigs operating in the GOM OCS during the reporting period.

Table 1: GOM Numbers at a Glance

Measure	2016	2017	2018
Total Activity Level*			
Wells with Activity	D.N.A.β	325	389
Wells Spudded	46	153	190
Active Operators	20	25	32
Rigs Operating	46	60	59
BOP Days	5,607	15,892	16,906
Reporting Operators	14	18	14
Rigs with Events	39	47	40
Total Events Reported**	827	1,421	1,196
Not-in-operation	643	1,176	1,024
In-operation	184	245	172
Stack Pulls†	13	20	18
LOC Events†	0	1	0
Top four operators' contribution‡			
Events	81.4%	81.9%	89.0%
Wells with Activity	D.N.A.	D.N.A.	36.0%
Wells Spudded	D.N.A.	32.7%	43.7%
BOP Days	59.2%	52.4%	47.3%

NOTE: Reporting period for 2016 is from July 28 to December 31.

* For the definitions of these measures, see Appendix C.

β D.N.A. (data not available).

** Total events reported includes those on rigs with subsea or surface BOP systems, and excludes non-rig events.

† Stack pulls are a subset of in-operation events, and LOC (loss of containment) events are a subset of stack pulls. For the definition of stack pull and loss of containment, see Appendix C.

‡ Top four operators' contribution is by number of notifications submitted in the listed year. For contribution of BOP days, there may be a slight underestimation due to limited data.

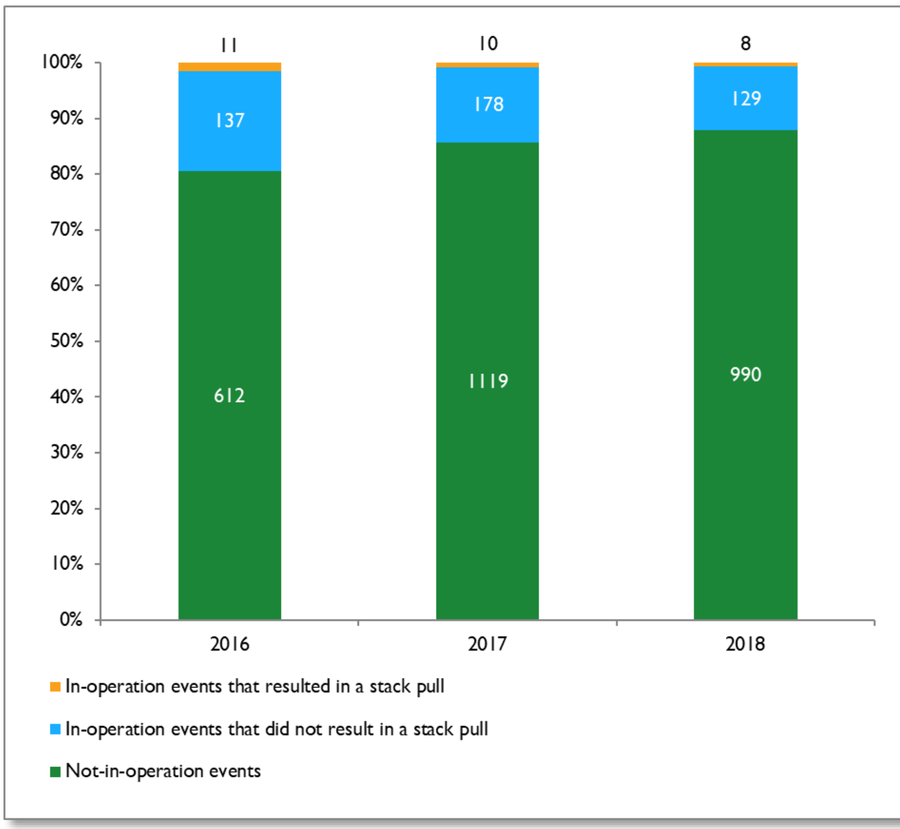
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

Table 1 presents the overall exposure measure statistics for rigs operating in the GOM OCS in 2016, 2017, and 2018. From 2017 to 2018, the amount of drilling and non-drilling activity increased, as evidenced by the higher number of *wells with activity*, the higher number of *wells spudded*, the increase in the number of active operators, and the increase in total *BOP days*. Though activity increased overall, the number of operators reporting failure events, as well as the number of rigs involved in those events, decreased, pointing to potential underreporting of equipment component failure events. Eighteen (18) stack pull events were reported in 2018, and no loss of containment events were reported.

Chapter 2: Events on Subsea BOP Systems

There were 1,127 equipment component failure events on subsea BOP systems (94.2 percent of all events) reported to SafeOCS in 2018, approximately the same percentage as reported in previous years. Figure 1 depicts the share of all years' reported events that were *not-in-operation*, *in-operation*, and *stack pulls*. Progressively, the percentage of not-in-operation events has increased over the years. This increase could be a result of more proactive maintenance and testing procedures leading to more failures being found before going into operation. The percent of in-operation events resulting in stack pulls increased slightly in 2018 (5.8 percent) from 2017 (5.3 percent).

Figure 1: Subsea System Events by Year and Operational Status



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

Key Statistics: Events on Subsea BOP Systems

- No loss of containment (LOC) event was reported in 2018.
- Most reported well control equipment component failure events (94.2 percent) pertained to subsea BOP systems rather than surface BOP systems.
- Most reported events (87.8 percent) occurred while the subsea system was not in operation, i.e., during planned periods of inspection, maintenance, and testing.
- Eight stack pulls were reported in 2018 as compared to 10 in 2017.
- Wear and tear was the most frequently listed root cause, reported for 52.4 percent of events.

Table 2: Subsea System Event Statistics

Measure	2016	2017	2018
Active Operators	D.N.A.	D.N.A.	16
Reporting Operators	10	11	10
Rigs with Events	28	29	24
Events Reported	760	1,307	1,127
Not-in-operation	612	1,119	990
In-operation	148	188	137
Stack Pulls	11	10	8
LOC Events	0	1	0
Top four operators*			
Events	84.1%	84.4%	90.8%
Wells with Activity	D.N.A.	D.N.A.	61.0%
Wells Spudded	D.N.A.	D.N.A.	D.N.A.
BOP Days	68.8%	64.7%	66.0%

NOTE: *Top four operators' contribution.

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

Table 3: Subsea System Exposure Measures

Measure	2016	2017	2018
Wells with Activity*			
Number of Wells with Activity	D.N.A.	165	172
Percent of Wells with Failures	D.N.A.	52.1%	33.1%
Avg. Failures per Well with Activity	D.N.A.	7.9	6.6
Rigs Operating*			
Number of Rigs Operating	30	32	31
Rigs with one BOP	12	10	9
Rigs with two BOPs	18	22	22
BOP Days*			
Number of BOP Days	5,155.0	10,719.7	9,962.7
*Event Rate**	147.4	121.9	113.1
Not-in-operation BOP Days	D.N.A.	4,396.0	4,285.7
*Not-in-operation Event Rate**	D.N.A.	254.5	231.0
In-operation BOP Days	D.N.A.	6,323.7	5,677.0
*In-operation Event Rate**	D.N.A.	29.7	24.1
Stack Pulls	11	10	8
*Stack Pull Event Rate**	D.N.A.	1.6	1.4
BOP Stack Runs*			
Total Stack Runs	D.N.A.	200	178
Successful Stack Runs	D.N.A.	167	152
In-oper. Failures per Succ. Stack Run	D.N.A.	1.1	0.9

KEY: avg—average; in-oper—in operation; succ—successful.

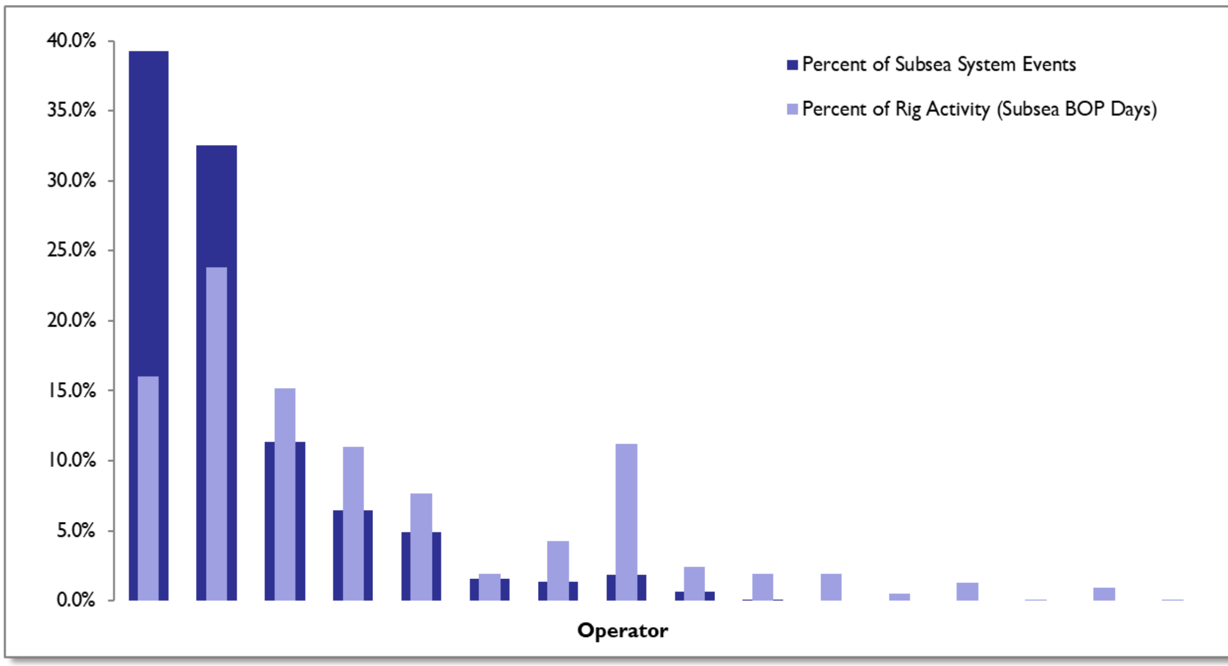
NOTE: *See Appendix C for definition.

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

Reporting Operators

Of 16 active operators in the GOM OCS that engaged in subsea BOP activity in 2018, 10 reported subsea system failure events.[8] Figure 2 shows subsea system events and rig activity (measured in BOP days) for the 16 active operators in 2018. The four operators that reported the most failures submitted 90.8 percent of subsea system events and accounted for 66.0 percent of rig activity (based on subsea BOP days), as compared to the top four reporting operators in 2017 that submitted 84.4 percent of events and accounted for 64.7 percent of production. Three of the top four reporting operators remained the same from 2017 to 2018, and the total number of reporting operators decreased from 11 to 10.

Figure 2: Subsea System Events and Rig Activity by Operator



NOTE: Subsea BOP days are based on all rigs with subsea BOP systems that operated in the GOM in 2018. Operator names have not been disclosed to preserve confidentiality.

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

Detection Methods

Failure events are discovered through several methods including, but not limited to, *functional testing*, *pressure testing*, *inspection*,[9] and *casual observation*. Knowledge about which detection methods are most

[8] Four operators reported events for both subsea and surface systems.

[9] Refers to company-conducted inspection.

likely to identify failures can lead to operational practices that increase early detection or failure prevention. Table 4 shows that on rigs with subsea BOP systems, events have been most frequently detected via functional testing, pressure testing, and inspection. This is potentially due to current testing and inspection requirements, as well as more proactive approaches to finding equipment issues before going into operation. It is worth noting that the percentage of failures identified during inspection has steadily increased from 2016 to 2018.

Table 4: How Subsea System Events Were Detected

Detection Method	2016		2017		2018	
	Count	Percent	Count	Percent	Count	Percent
Functional Testing	229	30.1%	544	41.6%	414	36.7%
Pressure Testing	170	22.4%	216	16.5%	176	15.6%
Inspection	66	8.7%	219	16.8%	253	22.4%
Casual Observation	139	18.3%	131	10.0%	91	8.1%
Continuous Condition Monitoring	83	10.9%	101	7.7%	62	5.5%
Periodic Maintenance	32	4.2%	39	3.0%	68	6.0%
Periodic Condition Monitoring	25	3.3%	29	2.2%	26	2.3%
Corrective Maintenance	11	1.4%	19	1.5%	30	2.7%
On Demand	5	0.7%	9	0.7%	7	0.6%
Total	**760**	**100.0%**	**1,307**	**100.0%**	**1,127**	**100.0%**

NOTE: Detection methods are sorted by the highest number of events reported across all years.

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

Table 5 below explores the relationship between the number of not-in-operation and in-operation failures found through each detection method. For nearly all detection methods across years, most events were detected while not-in-operation. The percent of events detected while not-in-operation has steadily increased for two of the top three detection methods (functional testing and inspection).

Table 5: How Subsea System Events Were Detected, by Operational Status

Detection Method	2016		2017		2018	
	Not-in-operation	In-operation	Not-in-operation	In-operation	Not-in-operation	In-operation
Functional Testing	88.1%	11.9%	93.8%	6.3%	96.6%	3.4%
Pressure Testing	72.4%	27.6%	79.6%	20.4%	78.4%	21.6%
Inspection	81.8%	18.2%	85.8%	14.2%	89.7%	10.3%
Casual Observation	82.0%	18.0%	78.6%	21.4%	80.2%	19.8%
Continuous Condition Monitoring	71.1%	28.9%	65.3%	34.7%	61.3%	38.7%
Periodic Maintenance	96.9%	3.1%	100.0%	0.0%	95.6%	4.4%
Periodic Condition Monitoring	60.0%	40.0%	55.2%	44.8%	47.6%	52.4%
Corrective Maintenance	100.0%	0.0%	100.0%	0.0%	96.7%	3.3%
On Demand	80.0%	20.0%	66.7%	33.3%	71.4%	28.6%

NOTE: Detection methods are sorted by the highest number of events reported across all years.

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

Observed Failures

For each failure notification, operators select an observed failure from a component-specific list. Examining trends and understanding changes in these observed failures may enable operators to recognize physical, mechanical, and structural issues within various components and systems. As shown in Table 6, *external leaks*, *internal leaks*, and *mechanical damage* were the top three observed failures in 2018 for subsea system events, which is consistent with 2016 and 2017 results. While it is not unexpected that external leaks continue to be the most frequently reported failure (since the majority of components control and contain fluids present during operations), seeing this trend allows operators to focus on and target external leak failures for possible improvement. Table 6 shows that the percentage of in-operation external leaks has decreased steadily from year to year. Proactive measures to detect external leaks before going into operation may explain the observed decrease. For all reporting years, external leaks mostly involved *control fluids*, rather than *drilling fluids* or *wellbore fluids*, which could contain hydrocarbons.

Table 6: Observed Failures on Subsea Systems

Observed Failure		2016		2017		2018	
		Count	Percent	Count	Percent	Count	Percent
External leak	*In-operation*	58	7.6%	75	5.7%	55	4.9%
External leak	*Not-in-operation*	291	38.3%	584	44.7%	470	41.7%
Internal leak		153	20.1%	314	24.0%	230	20.4%
Mechanical damage		71	9.3%	94	7.2%	143	12.7%
Inaccurate indication		28	3.7%	28	2.1%	33	2.9%
Fail to seal		16	2.1%	25	1.9%	27	2.4%
Fail to provide fluid		6	0.8%	2	0.2%	28	2.5%
Other observed failures*		137	18.0%	185	14.2%	141	12.5%
Total		**760**	**100.0%**	**1,307**	**100.0%**	**1,127**	**100.0%**

NOTE: ******Other observed failures* consist of those failures with 35 or fewer total events across years. Observed failures are sorted by the highest total across years.

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

Investigating the relationship between detection method and type of observed failure may provide insight into which detection methods are most helpful in targeting which types of failures. Table 7 shows a predominant detection method was associated with certain observed failure types, such as functional testing with external leaks, and inspection with mechanical damage. The data also shows that each failure type was often detected in various ways. For example, though most mechanical damage events (178) were found during inspection, the remaining 130 were found during functional testing, pressure testing, periodic maintenance, and casual observation, which suggests that the latter methods may be just as useful for detecting failures. For external leaks, 656 were found via functional testing, and 877 were found during pressure testing, inspection, and casual observation, which suggests that using a variety of detection methods may represent a potential best practice.

Table 7: Methods Used to Detect Each Observed Failure Type, 2016-2018

Detection Method	Observed Failure				
	External leak	Internal leak	Mechanical damage	Inaccurate indication	Fail to seal
Functional Testing	656	294	46	37	6
Pressure Testing	255	206	9	4	42
Inspection	217	57	178	9	8
Casual Observation	214	41	22	13	6
Continuous Condition Monitoring	88	37	6	15	3
Periodic Maintenance	49	33	25	3	1
Periodic Condition Monitoring	31	11	1	7	0
Corrective Maintenance	18	16	14	1	2
On Demand	5	2	7	0	0
Total	**1,533**	**697**	**308**	**89**	**68**

NOTE: Both detection method and observed failure are sorted by frequency of reporting across all years.

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

Events by Subunit

Each well control equipment subunit[10] has unique characteristics that may provide insight into reported equipment component failure events. Some subunits (such as the BOP stack) vary in the number of subsystems and components that serve as redundancies, depending on operator equipment specifications. For the subunits with potential variability in redundancy, an operator may add redundancies so that the BOP may not need to be retrieved for operations to continue in the event of a component failure. In contrast, redundancy is not applicable to some other subunits (such as the riser system) due to physical space limitations. For example, the *wellhead connector*, located below the BOP and closer to the well, is the most critical component and does not have the physical capability for redundancy. Two other items that are not protected by redundancy are the *riser connector* and the *riser adaptor*.

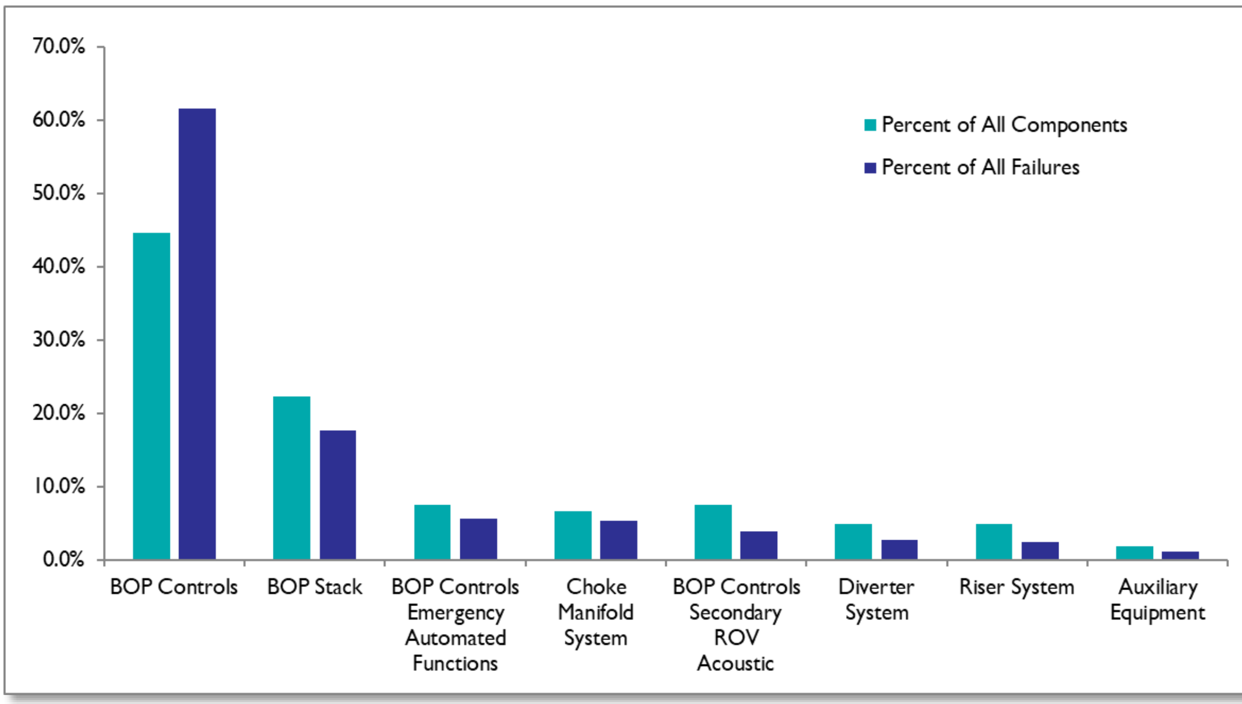
Among the subunits, the BOP controls subunit has yielded the highest proportion of events each year.[11] More interestingly, the BOP controls subunit shows the greatest difference between share of failures

[10] Reference Appendix C for the definition of subunit.

[11] Component counts per subunit are based on subject matter expert estimates of component counts for a "baseline" subsea BOP system.

(61.5 percent) and share of total components (44.6 percent) compared to other subunits, as shown in Figure 3 below. This finding may be due to the fact that the majority of components within the control systems are hydraulic or electronic control components which are relatively fragile compared to equipment on other subunits. Also, electronic components in the field are often upgraded more frequently than the hardware components they operate, and parts which are not as compatible as previous versions may fail at higher rates.

Figure 3: Distribution of Subsea System Components and Events by Subunit, 2016-2018



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

Similar detection methods, observed failures, and root causes of reported events were found across subunits, apart from the following observations. For all subunits except the riser system, the most frequently reported detection method is not-in-operation testing.[12] For the choke manifold system, nearly as many failures were found during in-operation pressure testing (66) as during not-in-operation pressure testing (68), suggesting that pressure testing is an important failure detection method for the choke manifold system and that more not-in-operation pressure testing has the potential to catch issues

[12] This includes both pressure and functional testing.

prior to going into operation. For the riser system, most of the 73 total reported events (65.8 percent) were found during a single inspection on one rig, showing the importance of proactive inspection.

Not-In-Operation Events

By definition, subsea system not-in-operation events occur when one of the following is true:

1. the BOP is not on the wellhead,
2. the lower marine riser package (LMRP) is not on the BOP, or
3. the BOP and LMRP are both on the wellhead, but initial subsea testing has not been completed.

Events discovered while not in operation are essential for identifying potential equipment issues before going into operation. Not-in-operation events are found via testing, inspection, routine maintenance, and other types of monitoring.

Phases of Testing and Initial Latch-Up Events

There are four distinct phases in which not-in-operation failures are found. The first, *between-well maintenance*, is the planned period of inspection and scheduled maintenance for all equipment. In subsequent phases, testing is conducted to prepare equipment for going into operation and check for any issues not detected during between-well maintenance.

1. BETWEEN-WELL MAINTENANCE: This is the pre-planned time for inspection and maintenance to find and resolve any equipment issues.
2. PRE-DEPLOYMENT TESTING: Also known as on-deck or stump testing, this is when the BOP stack equipment is tested on the rig before the stack is lowered into the water. This phase is used to ensure that the equipment is ready for deployment and to find any issues that were not discovered during between-well-maintenance.
3. DEPLOYMENT TESTING: This phase is after pre-deployment testing while the BOP is being lowered, or deployed, to the wellhead. System monitoring and testing are conducted throughout this process.
4. INITIAL LATCH-UP TESTING: This is the final phase and is similar to deployment testing, but with the added element of hydrostatic pressure due to operational depth. The BOP must pass all initial latch-up testing before going into operation.

Though most not-in-operation events are found during between-well-maintenance or pre-deployment testing, some are also found during deployment testing or initial latch-up testing. Depending on the specific component, system/component redundancy, and other circumstances, if a component event is found during deployment testing or initial latch-up testing, the operator may be able to repair the failed component using an ROV or continue operations without repair. Without repair or redundancy, the BOP stack must be retrieved to repair the component, causing operational delays.

As shown in Table 8, 48 events were found during deployment testing or initial latch-up testing in 2018. Twenty-five of these events contributed to 19 BOP stack retrievals; in some cases, multiple failures contributed to a single retrieval. By definition, retrievals are not considered stack pulls, as the BOP is not yet in operation. However, nine of these retrievals occurred due to component events found during initial latch-up testing, the final phase of testing before going into operation. These retrievals potentially caused significant cost and operational delays and could have resulted in stack pulls had the events not been discovered during the final testing phase. The costs associated with a stack retrieval are similar to a stack pull. However, since the BOP has not yet gone into operation, the well is not open and therefore does not need to be made safe before retrieving the BOP stack.

Table 8: Subsea System Events Found During the Last Two Phases of Testing

Measure	Events Found During Deployment Testing*	Events Found During Initial Latch-up Testing	Total
Total Events	29	19	48
Operations continued without repair	0	2	2
Component repaired	16	5	21
Events contributing to stack retrieval	13	12	25
Stack retrievals	10	9	19

NOTE: *Deployment testing includes any failures found during well hopping and pulling/retrieving. The 19 stack retrievals were a result of 25 events (multiple failures occurred before resulting in a single retrieval).

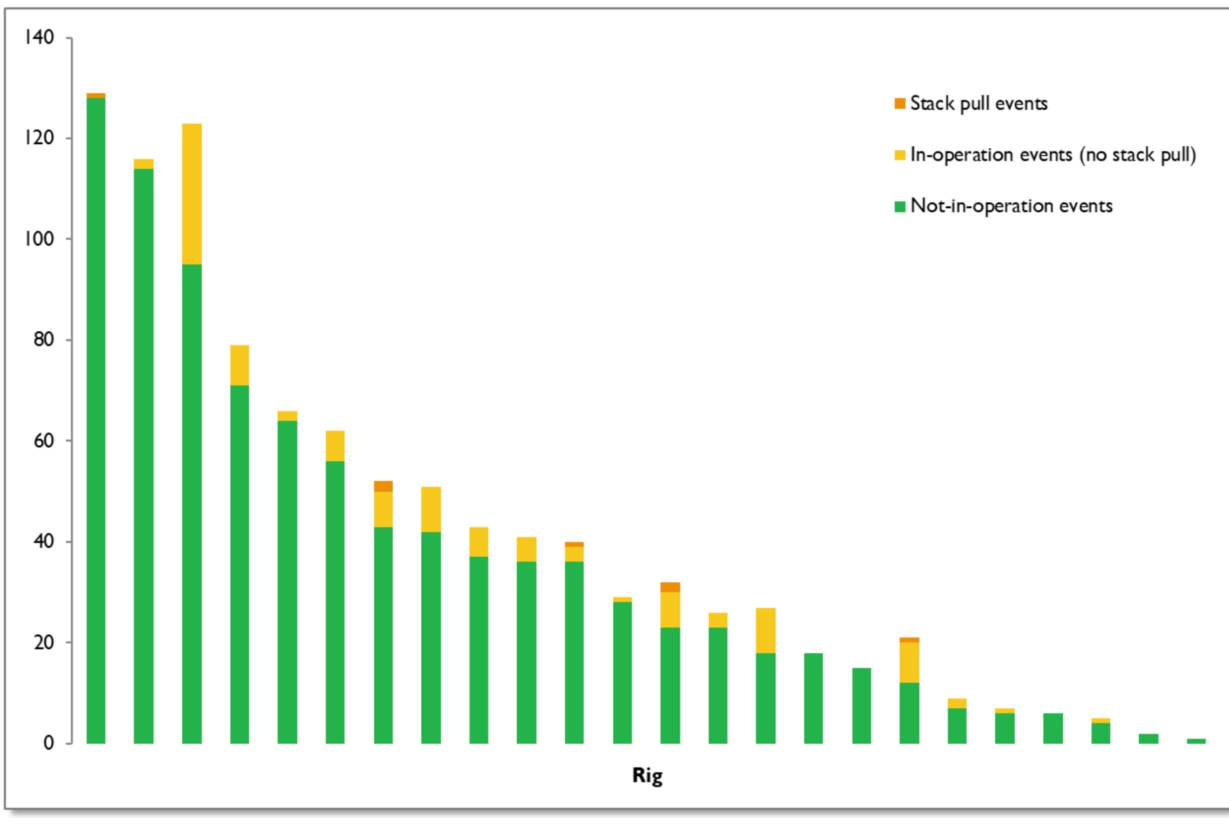
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

While all 48 events included in Table 8 involved systems or components that can be thoroughly tested prior to the last two testing phases, some systems and components can be only partially tested prior to the last two phases as they are not physically connected to the system or exposed to the full effects of hydrostatic pressure until the BOP has reached its operational depth. The latter include the riser system, telescopic joint, stack mounted electrical equipment, and wellhead connector. In 2018, 69 subsea system events involved systems or components which can be only partially tested before the initial latch-up phase. For 65 of these, the event occurred during either between-well maintenance or pre-deployment testing. The remaining four occurred after the BOP had passed all testing and was in operation. In other words, the vast majority (94.2 percent) of these events were found prior to operations and prior to the last two phases of testing.

Not-In-Operation Events and Rig Activity

Figure 4 compares not-in-operation, in-operation, and stack pull events for rigs with subsea BOP systems in 2018. With a few exceptions, the number of not-in-operation events has an inversely proportional relationship to in-operation events. This finding indicates that rigs with a higher incidence of not-in-operation failures tend to have fewer in-operation events.

Figure 4: Events on Rigs with Subsea BOP Systems



NOTE: Rigs are sorted by highest number of not-in-operation events.

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

Rigs with higher not-in-operation rig activity (measured in *stack runs*[13]) have a higher likelihood of experiencing not-in-operation events. To compare rates of reported not-in-operation events between rigs, a reporting ratio was calculated for each rig and adjusted using stack runs as a surrogate measure of rig activity:

$$\text{Adjusted reporting ratio for Rig "A"} = \frac{\text{Rig A's proportion of not-in-operation events}^{14}}{\text{Rig A's proportion of stack runs}^{15}}$$

Figure 5 shows the ratio for each rig, calculated using 2017 and 2018 data. The line intersecting the graph at the value of 1.0 represents the baseline reporting ratio where a rig's not-in-operation event reporting is proportional to its level of activity relative to other rigs with reported events. A ratio greater than 1.0 indicates potentially disproportionately higher reporting of not-in-operation events, and similarly a ratio less than 1.0 indicates potentially disproportionately lower reporting of not-in-operation events. As shown in Figure 5, 14 rigs are above the baseline (shown in green) and 17 rigs are below it (shown in yellow).

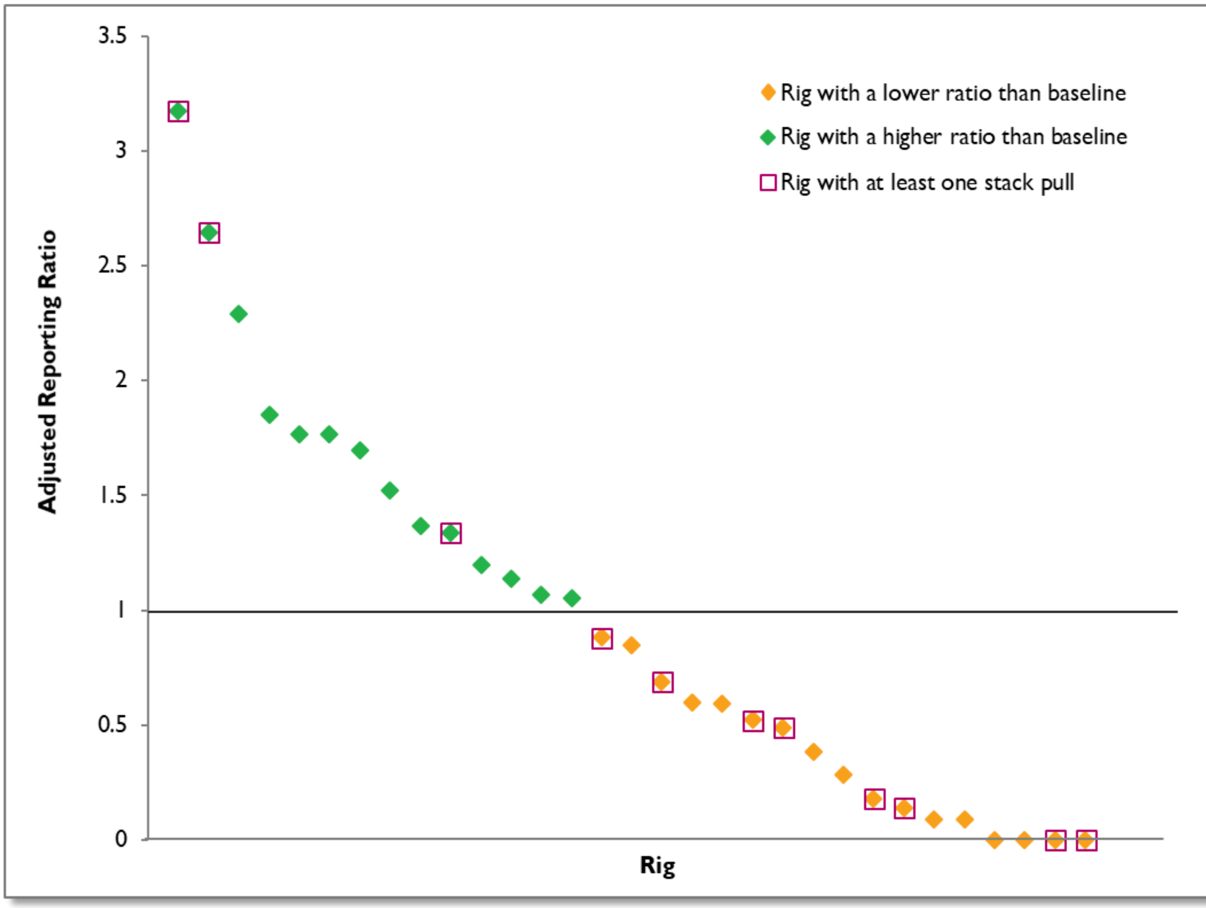
Figure 5 also shows which rigs experienced stack pulls (shown as an overlaid, outlined shape). Of the 14 rigs with higher relative reporting of not-in-operation events, three experienced at least one stack pull (21.4 percent). Of the 17 rigs with lower relative reporting of not-in-operation events, seven experienced at least one stack pull (41.2 percent). Considering all stack pulls, the number that occurred on rigs below the baseline (11) was almost double the number that occurred on rigs above the baseline (6). This analysis provides further support for an inversely proportional relationship between not-in-operation events and the occurrence of a stack pull (i.e., more not-in-operation failures found might lead to fewer stack pulls).

[13] Also called a stack deployment, a stack run is the activity of deploying, or "running" a subsea BOP stack from the rig floor to the subsea wellhead. For the full definition, see Appendix C.

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

[15] Rig A's stack runs divided by the total stack runs for all rigs with reported events.

Figure 5: Subsea System Not-In-Operation Events Relative to Rig Activity, 2017 & 2018



NOTE: Chart includes rigs that reported, via WAR, at least one day of activity in either 2017 or 2018.

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

In-Operation Events

In-operation events occur after the subsea BOP stack is latched on the wellhead and initial latch-up tests are successfully completed. In-operation events are considered more critical than not-in-operation events because of the potential for a well control incident. In 2018, 12.2 percent of subsea system failures occurred while in operation, compared to 14.4 percent in 2017 (see Table 2).

In-operation events can sometimes be corrected, isolated, or bypassed safely until the subsea BOP stack can be pulled to the surface to repair or replace the failed component. Also, some events do not disable the component in its entirety, and the system can still perform its necessary safety function. For example, a hydraulic valve can have a slight leak when it is commanded to open but still can close when needed. When a failure completely inhibits a barrier (such as an *annular preventer* or *pipe ram preventer*) from performing its safety function (i.e., to close and seal a well), it is deemed more severe and must be addressed before operations can continue. If the failure cannot be addressed while the BOP remains attached to the wellhead, preparations are made to ensure well safety before a stack pull is initiated.

In 2018, six subsea system in-operation failures disabled a barrier, and four of those resulted in stack pulls, resulting in a 66.7 percent stack pull rate for those events where a barrier was disabled. However, due to low numbers and the unique circumstances of each event, the rate can only serve as a starting point for further analysis. A larger data set is needed for more meaningful, multi-year analysis.

Subsea Stack Pulls

In a subsea stack pull, either the BOP is removed from the wellhead or the LMRP is removed from the BOP stack to repair or replace a failed component. A stack pull is required when a component failure occurs in operation that prevents the system from performing a necessary safety function; it cannot be corrected, isolated, or bypassed; and redundancy does not allow operations to continue under an MOC process.

A stack pull by definition is an unplanned event; when planned, such as after end-of-well activities or before anticipated severe weather conditions (e.g., a hurricane), it is typically referred to as a stack retrieval. A stack retrieval can also be unplanned if it occurs before the stack is in operation, i.e., at any point after deployment but before passing the initial latch-up tests.

The rate of in-operation events leading to stack pulls was compared for all reporting years, as shown in Table 9. Across years, the stack pull rate ranges from 5.3 to 7.4 percent. The table also lists the observed failure for each subsea stack pull, and the total number of stack pulls in each year associated with that observed failure. Across the reporting years, external leaks and mechanical damage were the two most common observed failures associated with stack pulls.

Table 9: Subsea Stack Pull Rates and Observed Failures

Measure	2016	2017	2018	All Years
In-operation events	148	188	137	473
Events leading to stack pulls	11	10	8	29
Stack pull rate	7.4%	5.3%	5.8%	6.1%
Observed failures associated with stack pulls:				
External leak	5	5	3	13
Mechanical damage	3	1	1	5
Internal leak	2	1	0	3
Fail to seal	0	0	2	2
Loss of power	1	0	0	1
Fail to close	0	1	0	1
Failure to transmit signal	0	1	0	1
Leakage	0	1	0	1
Blockage	0	0	1	1
Incorrect timing	0	0	1	1

NOTE: Stack pull rate is the number of stack pulls as a percentage of in-operation events.

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

The reported stack pulls occur across a variety of subunit, item (i.e., subsystem), and component combinations. The component failures affected barriers (e.g., *blind shear ram preventer*, *pipe ram preventer*), control systems (e.g., *BOP control pod*), and safety systems (e.g., *autoshear deadman EHBS*). Table 10 shows the subsystems, components, and observed failures for events leading to stack pulls in 2018. Importantly, not all failures are of equal potential consequence or have the same likelihood of occurring. For example, external leaks can lead to different outcomes depending on the subsystem, component, and observed failure involved. As shown in Table 10, of the 14 external leaks of piping/tubing on the autoshear deadman EHBS, one was in operation, and it resulted in a stack pull (100.0 percent). In comparison, of the 24 external leaks on SPM valves on the BOP control pod, five were in operation, but only one resulted in a stack pull (20.0 percent). These differences can be partially attributed to the fact that piping/tubing does not have redundancy and SPM valves do, as well as low numbers of events for these combinations.

Table 10: Component Combinations Associated with Reported Subsea Stack Pulls

Associated Subsystem	Failed Component	Observed Failure	Total Events	In-operation Events	Stack Pulls
Autoshear Deadman EHBS	Piping Tubing	External leak	14	1	1
	Timing Circuit	Incorrect timing	1	1	1
BOP Control Pod	Piping Tubing	External leak	17	1	1
	SPM Valve	External leak	24	5	1
Pipe Ram Preventer	Ram Block Seal	Fail to seal	16	2	1
Riser	Choke and Kill Line	Blockage	1	1	1
Shear Ram Preventer	Ram Block Hardware	Mechanical damage	8	1	1
	Ram Block Seal	Fail to seal	4	1	1
Total			**85**	**13**	**8**

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

Table 11 shows the subsystems, components, and observed failures for events leading to stack pulls across all reporting years. For the listed component combinations, 28.7 percent of reported in-operation events led to a stack pull; however, high variability exists between component combinations. For example, of 11 instances of leakage on the packing element on the annular preventer, only one led to a stack pull. In contrast, the sole reported instance of mechanical damage on the same subsystem and component led to a stack pull. Whether due to redundancy, specific testing and maintenance procedures, age, or accessibility, some component combinations may be more likely to lead to a stack pull if they experience an in-operation event. Component combinations with higher relative stack pull rates may warrant increased attention in efforts to reduce in-operation events.

Table 11: Component Combinations Associated with Reported Subsea Stack Pulls, 2016-2018

Associated Subsystem	Failed Component	Observed Failure	Total Events	In-operation Events	Stack Pulls
BOP Control Pod	Interconnect Cable	Mechanical damage	3	2	1
	Piping Tubing	External leak	43	7	1
	Regulator	External leak	140	4	1
		Internal leak	35	1	1
	SEA (Subsea Electronic Assembly)	Loss of power	6	2	1
	SPM Valve	External leak	114	17	1
BOP Controls Stack Mounted	Electrical Connector	Failure to transmit signal	1	1	1
	Piping Tubing	External leak	44	5	1
	Shuttle Valve	External leak	45	3	1
Autoshear Deadman EHBS	Piping Tubing	External leak	13	2	2
	SPM Valve	External leak	20	1	1
		Fail to close	3	1	1
	Timing Circuit	Incorrect timing	2	1	1
	Trigger Valve	External leak	8	4	1
Annular Preventer	Operating System Seal	External leak	12	1	1
		Internal leak	19	2	1
	Packing Element	Leakage	11	5	1
		Mechanical damage	1	1	1
Pipe Ram Preventer	Bonnet Face Seal	External leak	6	1	1
	Hardware & Mechanical	Mechanical damage	13	1	1
	Ram Block Hardware	Mechanical damage	9	4	1
	Ram Block Seal	Fail to seal	41	12	1
Shear Ram Preventer	Bonnet Operating Seal	External leak	29	3	1
	Ram Block Hardware	Mechanical damage	22	1	1
	Ram Block Seal	Fail to seal	17	6	1
Stack Choke and Kill System	Choke and Kill Valve	Internal leak	30	9	1
Riser	Choke and Kill Line	Blockage	1	1	1
Telescopic Joint	Packer	External leak	3	3	1
Total			691	101	29

KEY: EHBS—emergency hydraulic backup system; SEA—subsea electronic assembly; SPM—sub-plate mounted.

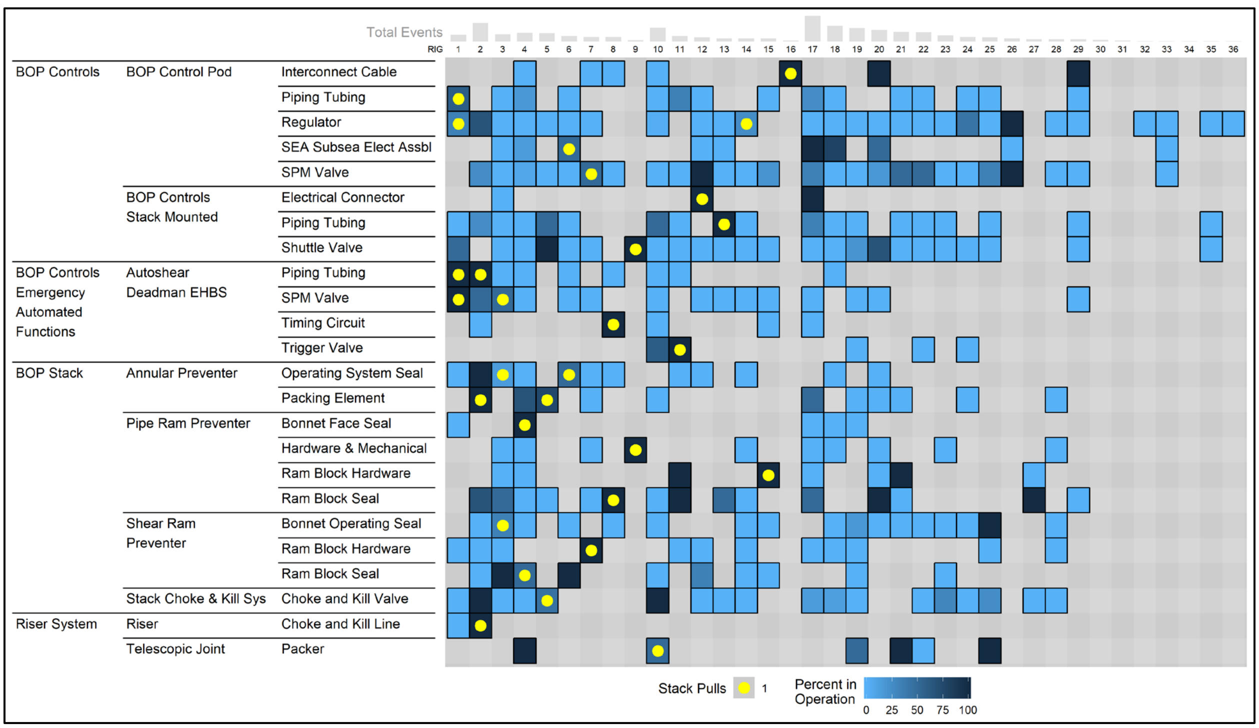
NOTE: The data in this table represent all events that occurred on the listed subsystem, component, and observed failure combination that led to the stack pull. For example, of 12 failures involving externally leaking operating system seals on the annular preventer subsystem, one was an in-operation event and it also resulted in a stack pull.

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

Figure 6 offers a visual representation of the distribution of components involved in in-operation events leading to at least one stack pull between 2016 and 2018, by rig. The shading of each grid square shows whether the listed rig (i.e., column) experienced a failure event for the listed component (i.e., row). Blue shading represents the percentage of in-operation events relative to total reported events for that component, with darker blue representing higher rates of in-operation events. Yellow dots represent stack pull events. Unshaded (gray) grid squares indicate the rig experienced no reported failure events for the listed component.

As the figure shows, squares with a stack pull generally have a darker shade (higher in-operation ratio), and squares without a stack pull generally have a lighter shade (lower in-operation ratio). More precisely, for component combination events associated with a stack pull (i.e., all squares showing a stack pull) 58.2 percent were in-operation events, while only 8.0 percent of events with no stack pull occurred in operation. This points toward a potentially increased likelihood for a stack pull on rigs with a higher percentage of in-operation events.

Figure 6: Components Involved in In-Operation Events Leading to a Stack Pull, by Rig, 2016-2018



KEY: EHBS—emergency hydraulic backup system; SEA—subsea electronic assembly; SPM—sub-plate mounted.

NOTE: Rigs shown experienced at least one reported event involving the listed component combination.

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

In addition to the subsea stack pull rate, which is measured as a percentage of in-operation events, subsea stack pulls were examined as a percentage of successful subsea stack runs. A stack run is considered successful if the equipment passes all initial latch-up testing and goes into operation; if a test is not passed or the BOP stack must be unlatched before going into operation, the stack run is considered unsuccessful. Since a single well operation may cross calendar years, the total number of stack pulls and successful stack runs for both 2017 and 2018 was considered.[16] During 2017 and 2018, there were 18 stack pulls and 319 successful stack runs (see Table 3), meaning 5.6 percent of successful stack runs eventually led to a stack pull.

Investigation and Failure Analysis (I&A)

Investigation and failure analysis (I&A) refers to any level of investigation beyond visual inspection conducted by a technical representative (such as a subsea engineer) on the rig, including root cause failure analyses (RCFA) involving the original equipment manufacturer (OEM) or qualified third party. For most events, the root cause can be easily discerned, and the component can be repaired, replaced, or otherwise corrected; this level of I&A is referred to as "cause immediately known."[17] For the remaining events, further I&A is required to determine the root cause. The results of these further investigations provide an opportunity for OEMs to evaluate and improve the reliability of their products and for equipment owners to improve their procedures.

Table 12: Investigation and Analysis of Subsea System Events

Year	Total Events	Events with Further I&A
2016	760	66 (8.7%)
2017	1,307	67 (5.1%)
2018	1,127	39 (3.5%)
Total	**3,194**	**172 (5.4%)**

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

For all reporting years, the percent of events with I&A completed beyond the level of cause immediately known is shown in Table 12. Overall, the share of subsea system events with further I&A completed has decreased each year.

[16] Because stack run data from the 2016 reporting period is limited, 2016 data is excluded from this analysis of subsea stack pulls as a proportion of successful subsea stack runs.

[17] The levels of I&A are described in more detail in section 9.0 of the SafeOCS well control failure reporting guidance document: *A User Guide for Reporting Well Control Equipment Failure*, U.S. Department of Transportation, Bureau of Transportation Statistics, Rev. 2.00 (Nov. 30, 2017), https://safeocs.gov/SafeOCSGuidanceRev2.pdf.

Root Causes of Subsea System Events

Understanding the root cause of an event is key to preventing reoccurrence and addressing any existing issues with equipment design, maintenance practices, and operating procedures. Table 13 shows the distribution of root causes across all reported events for each year and the percent of each root cause determined through further I&A. As shown in the table, both *design issue* and *QA/QC manufacturing* have been increasingly listed as the root cause of component failures from 2016 to 2018. The relative increase in reporting of these root causes does not necessarily indicate an actual increase in QA/QC manufacturing or design issues in the industry, but rather that these issues have been increasingly listed as the reason for failures. This shift may indicate that issues requiring only one or two parties to correct (such as maintenance errors and procedural errors) are being resolved more quickly, while those issues requiring more parties to remedy (design issues and QA/QC manufacturing) are taking longer to resolve.

Table 13: Subsea System Event Root Causes

Root Cause	Percent of All Events			Determined through Further I&A		
	2016	2017	2018	2016	2017	2018
Wear and Tear	33.2%	57.7%	52.4%	3.2%	2.8%	1.0%
Maintenance Error	17.1%	13.5%	9.5%	14.6%	4.0%	0.9%
Design Issue	5.3%	8.3%	14.3%	32.5%	19.3%	5.6%
QA/QC Manufacturing	3.4%	5.9%	12.0%	23.1%	5.2%	5.9%
Procedural Error	2.9%	2.0%	3.1%	36.4%	15.4%	17.1%
Documentation Error	0.4%	0.6%	0.5%	33.3%	12.5%	0.0%
Other*	37.8%	12.0%	8.3%	3.8%	5.7%	9.7%

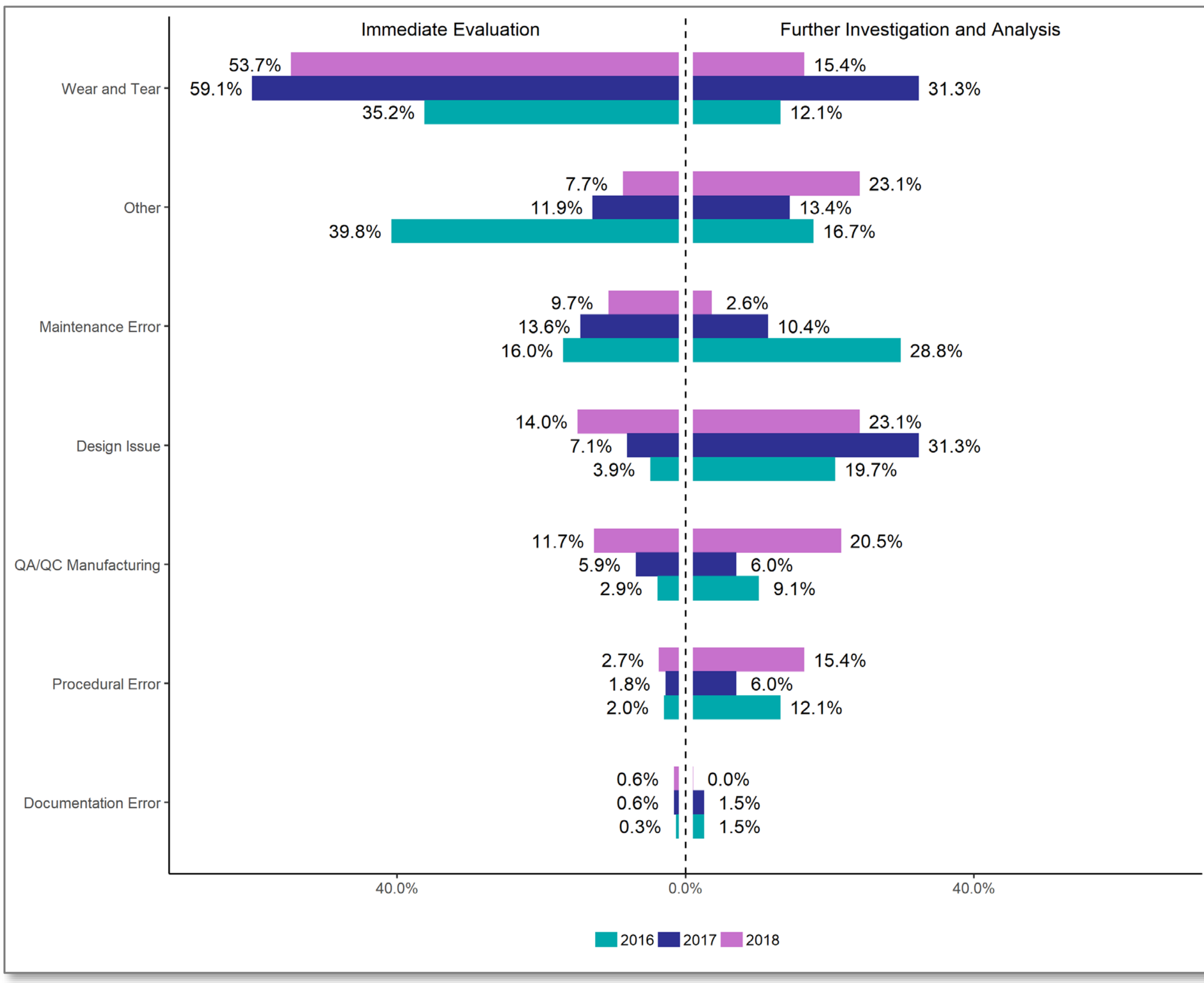
NOTE: *The selection of *other* by the submitter allows for entry of a root cause that may not precisely fit the other selections. Most submitted root causes under *other* have been *RCFA required*.

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

As shown in Table 13, from 2016 to 2018, fewer determinations of *design issue* as the root cause have been made through further I&A. This decrease could indicate that design issues have been increasingly easier to identify and confirm (i.e., failures have not required further I&A). Except for *procedural error* and *other*, this trend is true for all root causes, suggesting that they are increasingly determined through an immediate evaluation. Possible reasons for the trend include an increase in practices, tools, resources, training, or knowledge available to on-site personnel determining the root cause of an event, or potentially a relative increase in events with known root causes recognizable from similar previous events. Alternatively, investigation efforts may have been focused only on a subset of the most significant failures, or available resources to perform further investigations may have decreased.

When further I&A is conducted, findings can reveal greater detail about the factors that led to a component event and, in some cases, uncover a different root cause than was suspected during the initial evaluation. Figure 7 shows the distribution of root cause determinations made through immediate evaluations versus through further I&A. The figure shows that immediate evaluation tends to favor wear and tear, whereas further I&A results in more determinations of design issue, QA/QC manufacturing, and procedural error relative to immediate evaluation.

Figure 7: How Root Causes Were Determined, 2016-2018



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

Root Causes of Subsea Stack Pulls

RCFAs by the OEM or a third party are expected to be carried out for events resulting in stack pulls and reoccurring failures.[18] RCFA documentation was sent to SafeOCS for three of the eight subsea stack pulls reported in 2018, as shown in Table 14. The root causes of the three events with submitted RCFA documentation were *wear and tear* (1) or *procedural error* (2). For the remaining five, the listed root cause was *design issue* (3) or *RCFA required* (2), meaning the RCFA is still pending. Without submission of additional RCFA documentation, the suspected root cause of the latter five events cannot be confirmed.

Table 14: Root Causes of Subsea Stack Pulls

Associated Subsystem	Failed Component	Root Cause	RCFA Status	Stack Pulls
Autoshear Deadman EHBS	Piping Tubing	Wear and Tear	Completed	1
	Timing Circuit	RCFA Required	Not sent to SafeOCS	1
BOP Control Pod	Piping Tubing	Procedural Error	Completed	1
	SPM Valve	Design Issue	Not sent to SafeOCS	1
Pipe Ram Preventer	Ram Block Seal	RCFA Required	Not sent to SafeOCS	1
Riser	Choke and Kill Line	Procedural Error	Completed	1
Shear Ram Preventer	Ram Block Hardware	Design Issue	Not sent to SafeOCS	1
	Ram Block Seal	Design Issue	Not sent to SafeOCS	1
Total				**8**

KEY: EHBS—emergency hydraulic backup system; SPM—sub-plate mounted.

NOTE: *RCFA Required* means the operator listed the root cause as *RCFA required*, and no further documentation has since been received.

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

Table 15 summarizes the subsystem, component, and root cause for all subsea stack pull events during 2016 to 2018. RCFA documentation was sent to SafeOCS for 13 of the 29 total events.

[18] See section 9.0 of the SafeOCS well control failure reporting guidance document: *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.

Table 15: Root Causes of Subsea Stack Pulls, 2016-2018

Associated Subsystem	Failed Component	Root Cause	RCFA Status	Stack Pulls
Annular Preventer	Operating System Seal	Design Issue	Completed	1
	Packing Element	Design Issue	Completed	1
Autoshear Deadman EHBS	Piping Tubing	Wear and Tear	Completed	1
	SPM Valve	Documentation Error	Completed	1
		Maintenance Error	Completed	1
BOP Control Pod	Interconnect Cable	Procedural Error	Completed	1
	Piping Tubing	Procedural Error	Completed	1
Pipe Ram Preventer	Bonnet Face Seal	Design Issue	Completed	1
	Hardware & Mechanical	Other	Completed	1
	Ram Block Hardware	Maintenance Error	Completed	1
Riser	Choke and Kill Line	Procedural Error	Completed	1
Shear Ram Preventer	Bonnet Operating Seal	Maintenance Error	Completed	1
Stack Choke and Kill System	Choke and Kill Valve	Design Issue	Completed	1
Multiple	Multiple	Multiple	Not sent to SafeOCS	16
Total				**29**

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

Wear and tear is a less expected root cause of subsea stack pull events because for subsea stacks, much of the equipment is located underwater and therefore inaccessible in operation, putting increased emphasis on the quality of maintenance, inspection, and testing carried out before running the stack. Between-well maintenance prepares the stack for the next well by conducting periodic maintenance on all well control equipment and replacing components if there is any doubt of their capability to last the expected duration of the coming well operation.

Wear and tear was determined to be the root cause for one stack pull event in 2018. In the RCFA information submitted to SafeOCS, the operator noted that wear and tear was chosen because the alternate choices for root cause on the data collection form were not applicable, and that shocks and vibrations from operations contributed to the component's connection failure. Since the age of the component was listed as 45 months, but the last visual check was 5.7 months prior, there may be reasonable doubt as to whether wear and tear was the true root cause in this case.

Without documentation of a comprehensive RCFA for a stack pull event, the ability to develop safety learnings is more limited. For all subsea stack pull events from 2016 to 2018, wear and tear was listed as the root cause for four events. RCFA documentation was sent to SafeOCS for only one of these, summarized above. For three of the events, the time since last maintenance was less than one year; it was not reported for the remaining event. For two of the events, the component age was not listed. Based on component ages and time since last maintenance, wear and tear is likely not a reasonable root cause.

Lessons Learned

Of 39 subsea system events with further I&A in 2018, 24 contained documentation listing follow-up actions addressing each root cause, summarized in Table 16. Some of the I&As contained findings applicable to other similar reported events, bringing the total number of events with listed follow-up actions to 32. Developing and implementing follow-up actions involves important communication paths between OEMs, equipment owners, and operators regarding causes of equipment failures, improvements, and preventive measures across the industry, and they can have the potential for industry-wide impact. For example, an identified design issue could lead to a design change for which an engineering bulletin or safety alert is issued that affects multiple operators and equipment owners.

The identified follow-up actions within documentation submitted to SafeOCS included equipment design changes; mitigation steps to improve training, documentation, or equipment source accuracy; and long-term corrective actions for the OEM, operator, or equipment owner. The listed actions serve as examples of how RCFAs can lead to improvements not only for an individual entity but also for the entire industry. For example, through an RCFA, an OEM may discover the need for an updated design of a component, which can be implemented across the industry to prevent a reoccurring failure, reducing risk and improving operations. In 2018, nine RCFAs mentioned previously published notices about a design, maintenance, or procedural change. Notices about these types of changes are critical to addressing issues as they arise.

Table 16: Follow-Up Actions on Subsea System Events

	Component	Root Cause	Root Cause Details	Recommended Follow-up Action
1	Accumulator	QA/QC Manufacturing	OEM substitute material was incorrect for the seal band, creating an interference fit with the pod accumulator shell/piston interface, preventing the free movement for correct operation.	OEM to accept back all faulty components under warranty for repair and revise applicable drawings.
2,3	Bonnet Operating Seal	Design Issue	Protruding o-ring did not have perforations per current design, which changed during the three years the o-ring was in service.	During repairs, rig owner should follow OEM documentation for new o-ring design to ensure it is bonded and has perforations.
		Wear and Tear	Shaft seal leaked after 58 months.	Rig owner implemented a preventive maintenance plan to replace ram shaft seal assembly at 30 months or sooner.
4	Choke and Kill Connector Receptacle Female	Design Issue	Nickel overlay damaged by foreign object.	OEM will change the design to improve the overlay material to resist expected foreign contaminants.
5	Choke and Kill Line	Procedural Error	U-tubing through choke line allowed cuttings to fall out of the base oil/mud interface creating a plug in the line.	Operator to modify procedures to avoid u-tubing through choke/kill line in a high cuttings environment.
6	Choke and Kill Operator Hardware	Design Issue	Design had allowed for excessive corrosion of cap screws, causing nose ring distortion and connector failure.	OEM will modify cap screw design for enhanced corrosion resistance.
7	Cylinder	Design Issue	Hard seal scuffing when stretching seal over shaft, causing excessive fluid flow leading to sealing lip folding over.	OEM updated design to prevent hard seal scuffing when stretching seal over shaft; new design was in testing at the time of this event.
8	Depth Compensated Accumulator	Procedural Error	Failure to precisely measure depth compensated bottle temperatures and hydraulically pack the system before conducting EHBS tests led to low accumulator volume and false failure indications.	Rig owner to update procedures to improve requirements for ensuring systems reach maximum hydraulic volume.
9	Filter	Design Issue	Design issue led to filter screen being rolled back on one side.	OEM to redesign the filter element.
10	Flowline Seal	Procedural Error	Over-pressurization caused a cut in seal.	Rig owner to make a procedural change based on previously published OEM documentation indicating proper pressure range for seal operation.

	Component	Root Cause	Root Cause Details	Recommended Follow-up Action
11	Hydraulic Tool	Design Issue	Design issue allowed hydraulic tool stem to loosen.	OEM to modify assembly/design to increase torque.
12	Inclinometer	Wear and Tear	Obsolete inclinometer failed after 14 months of use.	OEM to supply newest revision of component.
13	Locking Device	Design Issue	Design issue allowed for operating piston seal to be compromised.	Lessons learned were recorded in the OEM report, but not provided to SafeOCS.
14	Operating System Seal	Design Issue	O-ring cord spacing and contraction issues over time caused leakage.	OEM recommends equipment owner to change to a bonded seal design (PA 30846) to ensure gap over allowable limit does not occur.
15	Packing Element	Design Issue	Design caused element cracking and failure to close after 66 cycles.	OEM to redesign element and improve QA/QC fatigue testing.
16,17	Piping Tubing	QA/QC Manufacturing	Tube fitting was loosened during either manufacturing, shipping, or installation. Defined processes are not in place to sufficiently test equipment after the manufacturing process.	OEM QA/QC procedures and equipment owner procedures to be updated and implemented.
		Other	Vibration and water-hammer shocks loosened tubular pipe fitting.	Rig owner to formalize the existing maintenance plan to ensure proper torque of tubular pipe fittings before deploying the stack.
18	Pressure Temperature Sensor	QA/QC Manufacturing	Intermittent insulation resistance failure in the primary sensor/cable connector.	OEM to modify pressure/temperature sensor (i.e., resistance temperature detector or RTD) mounting and QC process. OEM also planning to redesign product to improve water resistance.
19	Ram Block Seal	Design Issue	Seal experienced inadequate bonding of metal/elastomer due to fluid exposure at high temperatures and corrosion migration.	OEM to redesign seal to be fully encased in rubber and update operating procedure to provide equipment ratings.
20	Regulator	Maintenance Error	Regulator seal plate was forcibly installed; Demineralized water leached nickel from tungsten carbide, reducing lubricity and causing cracked seal ring to score plates.	Equipment owner should carefully follow assembly procedures and water hardness standards.

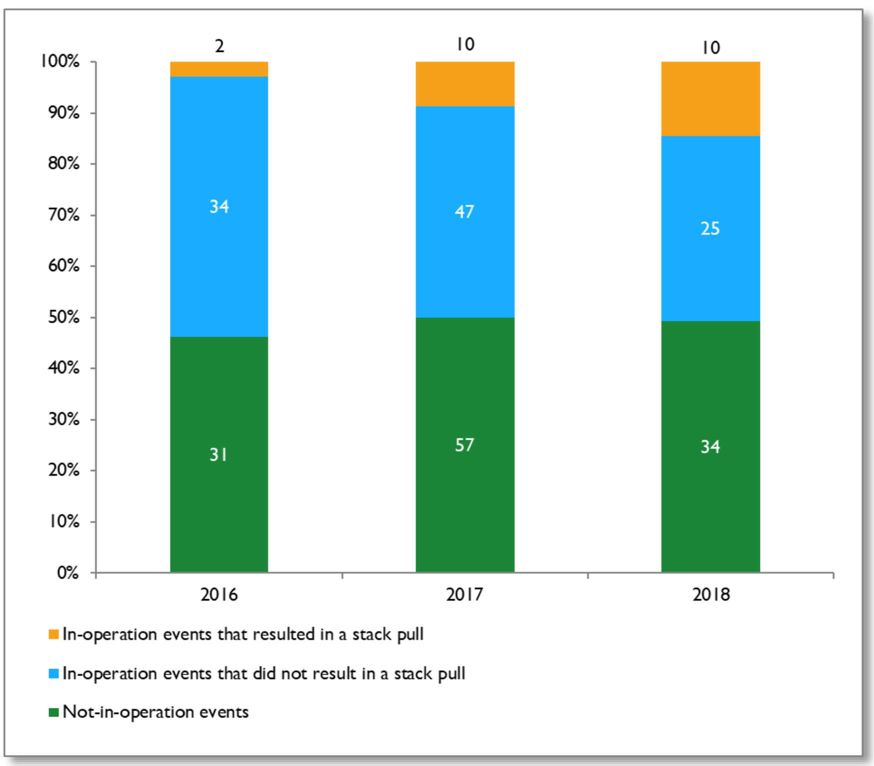
	Component	Root Cause	Root Cause Details	Recommended Follow-up Action
21	Ring Gasket	Other	RCFA inconclusive, but pressure loss and resulting leak determined to have happened due to a loss of preload in the flange-joint connection.	OEM updated torque values in maintenance plan procedure. Rig owner implemented the updated OEM procedures on checking proper torque and purchased a new tool for checking torque.
22	Riser Control Box (RCB)	QA/QC Manufacturing	OEM QA/QC testing did not include the internal connector, allowing a defective part to be shipped.	OEM to update procedure to ensure RCB is tested prior to shipment.
23	Slide Shear Seal Valve	Design Issue	At low pressure, elastic deflection caused piston impingement on seal ring causing leakage.	OEM to redesign valve to prevent impingement and leakage.
24	Studs and Nuts	QA/QC Manufacturing	Surface flaw led to heat treat crack on 20E API BSL-1 nut. API 20E BSL-1 bolting has no quality inspection requirements beyond what is designated by applicable ASTM specifications, so surface nondestructive evaluation was not an order requirement.	OEM applied additional QA/QC magnetic particle inspection process to lower grade of bolting.

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

Chapter 3: Events on Surface BOP Systems

There were 69 equipment component failure events on surface BOP systems (5.8 percent of all events) reported to SafeOCS in 2018, a lower percentage than reported in previous years. The distribution of surface BOP not-in-operation and in-operation events remained approximately the same from 2017 to 2018. However, as shown in Figure 8, the percent of in-operation events resulting in stack pulls increased from 17.5 percent in 2017 to 28.6 percent in 2018. The lower percentage of not-in-operation failures for surface systems (49.3 percent)[19] compared to subsea systems (87.8 percent)[20] reflects the conventional field practice of conducting more thorough pre-deployment inspection, maintenance, and testing on subsea systems. Rigs with surface BOP systems perform the same basic functions as rigs with subsea BOP systems; however, as previously noted, surface BOPs are less complex due to having fewer components. In addition, the equipment is readily accessible on deck for installation and maintenance activities.

Figure 8: Surface System Events by Year and Operational Status



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

[19] See Table 17. 34 / 69.

[20] See Table 2. 990 / 1,127.

Key Statistics: Events on Surface BOP Systems

- No loss of loss of containment (LOC) event was reported in 2018.
- Only 69 surface BOP system events were reported to SafeOCS, representing 5.8 percent of all reported events.
- About half of reported events (49.3 percent) occurred while the surface system was not in operation, i.e., during planned periods of inspection, maintenance, and testing.
- While the percent of in-operation events resulting in stack pulls increased in 2018 (28.6 percent) from 2017 (17.5 percent), reported events are too few to generalize this trend to the industry.
- *Wear and tear* and *other* were the most frequently listed root causes, reported for 56.5 percent and 23.2 percent of events, respectively.

Table 17: Surface System Event Statistics

Measure	2016	2017	2018
Active Operators	D.N.A.	D.N.A.	24
Reporting Operators	6	10	8
Rigs with Events	11	18	16
Events Reported	67	114	69
Not-in-operation	31	57	34
In-operation	36	57	35
Stack Pulls	2	10	10
LOC Events	0	0	0
Top four operators*			
Events	79.1%	72.9%	81.4%
Wells with Activity	D.N.A.	D.N.A.	38.2%
Wells Spudded	D.N.A.	D.N.A.	D.N.A.
BOP Days	64.5%	52.8%	43.7%

NOTE: *Top four operators' contribution.

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

Table 18: Surface System Exposure Measures

Measure	2016	2017	2018
Wells with Activity*			
Number of Wells with Activity	D.N.A.	160	217
Percent of Wells with Failures	D.N.A.	22.5%	12.0%
Average Failures per Well with Activity	D.N.A.	0.70	0.30
Rigs Operating*			
Number of Rigs Operating	16	28	28
BOP Days*			
Number of BOP Days	1,556.0	5,172.0	6,943.0
*Event Rate**	43.1	22.0	9.9
Not-in-operation BOP Days	D.N.A.	1,530.8	1,899.9
*Not-in-operation Event Rate**	D.N.A.	37.2	17.9
In-operation BOP Days	D.N.A.	3,641.2	5,043.1
*In-operation Event Rate**	D.N.A.	15.7	6.9
Stack Pulls	2	10	10
*Stack Pull Event Rate**	D.N.A.	2.7	2.0
BOP Stack Starts**			
Total Stack Starts	D.N.A.	186	224
Successful Stack Starts	D.N.A.	170	217
In-oper. Failures per Succ. Stack Start	D.N.A.	0.34	0.16

KEY: avg—average; in-oper—in operation; succ—successful.

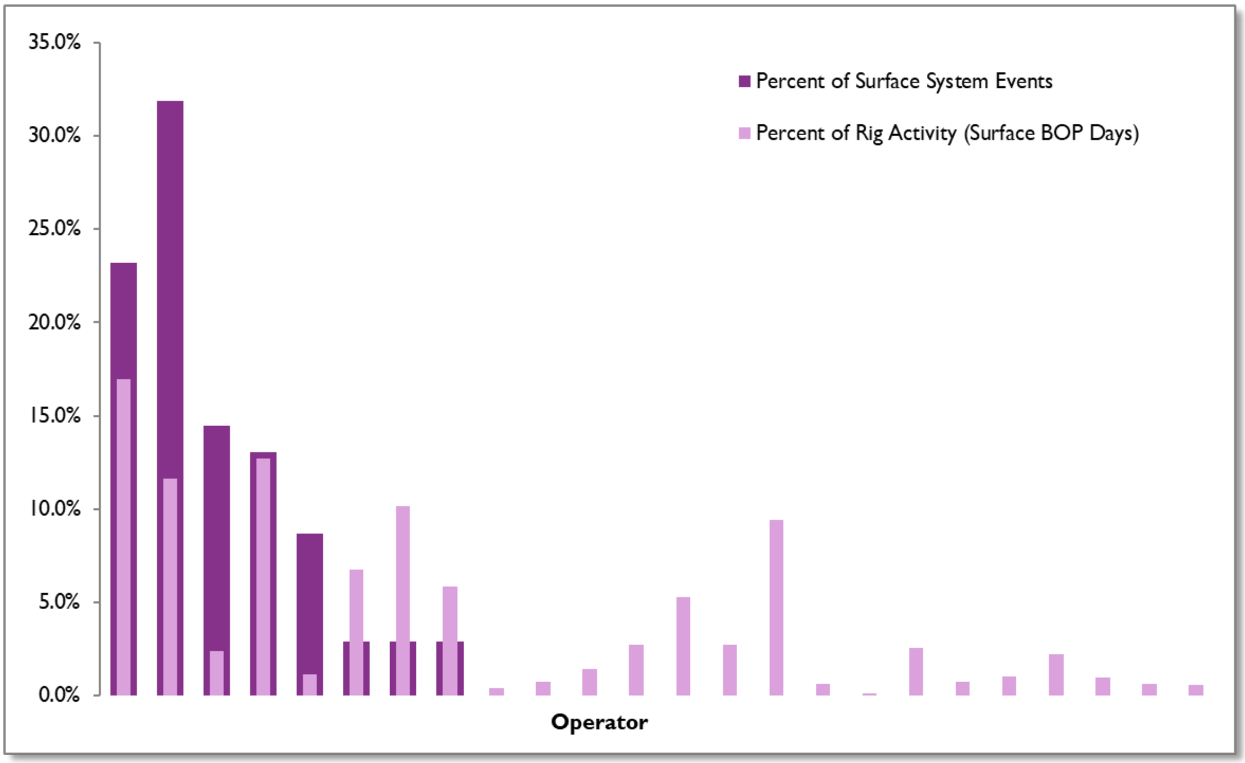
NOTE: *See Appendix C for definition. **In this report, *BOP stack start* means when a surface BOP stack is assembled on the wellhead.

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

Reporting Operators

Of 24 active operators in the GOM OCS that engaged in surface BOP activity in 2018, eight reported surface system failure events.[21] Figure 9 shows surface system events and rig activity (measured in BOP days) for the 24 active operators in 2018. The four operators that reported the most failures submitted 81.4 percent of surface system notifications, and accounted for 43.7 percent of rig activity (based on surface BOP days), as compared to the top four reporting operators in 2017 that submitted 72.9 percent of notifications and accounted for 52.8 percent of rig activity. The top four reporting operators remained the same from 2017 to 2018, and the total number of reporting operators decreased from 10 to eight.

Figure 9: Surface System Events and Rig Activity by Operator



NOTE: Surface BOP days are based on all rigs with surface BOP systems that operated in the GOM in 2018. Operator names have not been disclosed to preserve confidentiality.

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

[21] Four operators reported events for both subsea and surface systems.

Detection Methods

Detection method options for subsea and surface BOP systems are the same; however, since surface equipment is more readily accessible throughout operations, the use of those detection methods varies from subsea BOP systems. Table 19 shows that on rigs with surface BOP systems, events have been most frequently detected via pressure testing across reporting years. Most events not detected through pressure testing were found through functional testing or casual observation. Testing as a whole is by far the most common detection method for finding surface BOP system events. Except for inspection, all other detection methods have decreased from year to year relative to testing.

Table 19: How Surface System Events Were Detected

Detection Method	2016		2017		2018	
	Count	Percent	Count	Percent	Count	Percent
Pressure Testing	37	55.2%	61	53.5%	44	63.8%
Functional Testing	9	13.4%	15	13.2%	11	15.9%
Casual Observation	10	14.9%	16	14.0%	5	7.2%
Continuous Condition Monitoring	6	9.0%	13	11.4%	4	5.8%
Inspection	2	3.0%	5	4.4%	5	7.2%
Periodic Condition Monitoring	1	1.5%	2	1.8%	0	0.0%
Corrective Maintenance	2	3.0%	0	0.0%	0	0.0%
On Demand	0	0.0%	2	1.8%	0	0.0%
Total	**67**	**100.0%**	**114**	**100.0%**	**69**	**100.0%**

NOTE: Detection methods are sorted by highest number of events reported across all years.

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

Table 20 below explores the relationship between the number of not-in-operation or in-operation failures found for each detection method. For the two most frequently reported detection methods (pressure testing and functional testing), the share of not-in-operation and in-operation events has remained relatively stable and evenly distributed between the two operational statuses.

Table 20: How Surface System Events Were Detected, by Operational Status

Detection Method	2016		2017		2018	
	Not-in-operation	In-operation	Not-in-operation	In-operation	Not-in-operation	In-operation
Pressure Testing	48.6%	51.4%	55.7%	44.3%	52.3%	47.7%
Functional Testing	77.8%	22.2%	66.7%	33.3%	72.7%	27.3%
Casual Observation	20.0%	80.0%	31.3%	68.8%	40.0%	60.0%
Continuous Condition Monitoring	33.3%	66.7%	38.5%	61.5%	100.0%	0.0%
Inspection	50.0%	50.0%	60.0%	40.0%	20.0%	80.0%
Periodic Condition Monitoring	0.0%	100.0%	0.0%	100.0%	0.0%	0.0%
Corrective Maintenance	50.0%	50.0%	0.0%	0.0%	0.0%	0.0%
On Demand	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%

NOTE: Detection methods are sorted by highest number of events reported across all years.

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

Observed Failures

As shown in Table 21, leaks remain the top observed failures for surface BOP system events, with internal leaks having the highest total across the entire reporting period. As with subsea systems, it is not unexpected that leaks are the most frequently observed failure, since most well control equipment consists of components controlling or containing the fluids present during operations. None of the reported leak events posed significant environmental risks.

Table 21: Observed Failures on Surface Systems

Observed Failure	2016		2017		2018	
	Count	Percent	Count	Percent	Count	Percent
Internal leak	31	46.3%	41	36.0%	15	21.7%
External leak	22	32.8%	31	27.2%	24	34.8%
Leakage	4	6.0%	7	6.1%	12	17.4%
Mechanical damage	2	3.0%	17	14.9%	3	4.3%
Fail to seal	6	9.0%	10	8.8%	5	7.2%
Other observed failures*	2	3.0%	8	7.0%	10	14.5%
Total	**67**	**100.0%**	**114**	**100.0%**	**69**	**100.0%**

NOTE: **Other observed failures* consist of those failures with 20 or fewer total events across years. For events reported as *leakage*, the reporter did not specify whether the leak was internal or external. Observed failures are sorted by the highest total across years.

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

Table 22 shows that the most commonly observed failures (leaks) were found most often via pressure or functional testing, the most common detection methods. The data also shows that a relatively high number of internal and external leaks were found via various other detection methods (61 events) compared to the number found via pressure testing (79 events). Similarly, a relatively high number of external leaks were found via casual observation (20 events) as were found via pressure testing (30 events). These observations may be partially attributed to the fact that surface equipment is readily accessible on deck, allowing the crew to detect issues visually.

Table 22: Methods Used to Detect Each Observed Failure Type, 2016-2018

Detection Method	Observed Failure				
	Internal Leak	External Leak	Leakage	Mechanical Damage	Fail to Seal
Pressure Testing	49	30	19	14	21
Functional Testing	12	13	2	3	0
Casual Observation	9	20	0	2	0
Continuous Condition Monitoring	9	7	0	2	0
Inspection	6	5	0	0	0
Periodic Condition Monitoring	1	2	0	0	0
Corrective Maintenance	1	0	1	0	0
On Demand	0	0	1	1	0
Total	**87**	**77**	**23**	**22**	**21**

NOTE: Both detection method and observed failure are sorted by frequency of reporting across all years.

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

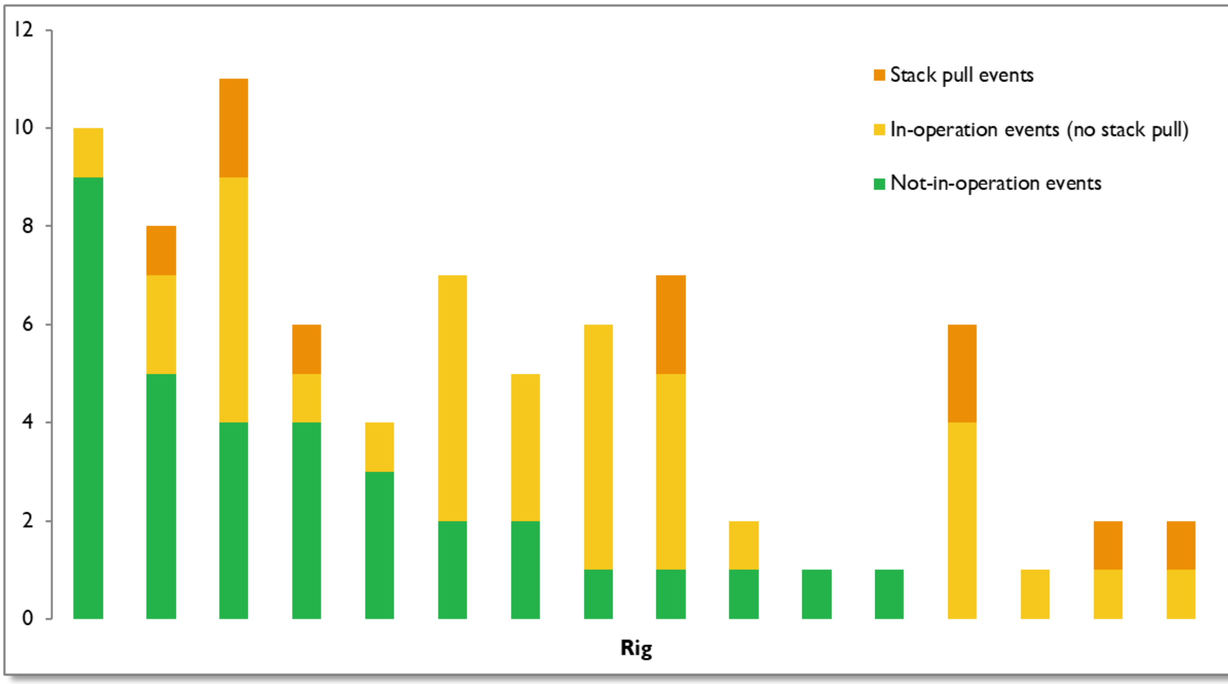
Not-In-Operation Events

Surface system not-in-operation events occur when the BOP is on either the deck or the wellhead, but initial latch-up tests have not yet been completed. Surface equipment undergoes inspections, testing, and other monitoring in relatively less detail while not in operation compared to subsea systems. In 2018, not-in-operation failures made up 49.3 percent of all surface system failures, consistent with the share reported in 2016 (46.3 percent) and 2017 (50.0 percent). The relatively even distribution of failures found in operation and not in operation may be partially explained by equipment remaining on deck during both not-in-operation and in-operation activities, facilitating the identification of issues during operations.

Not-In-Operation Events and Rig Activity

Figure 10 compares not-in-operation, in-operation, and stack pull events for rigs with surface BOP systems in 2018. With a few exceptions, the data shows that rigs that experienced more not-in-operation failures experienced fewer stack pulls. However, due to the limited number of reported failures for surface systems, generalizing this observed pattern to the industry is premature. BTS will conduct additional analysis as more data becomes available.

Figure 10: Events on Rigs with Surface BOP Systems



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

In-Operation Events

Similar to subsea BOP systems, in-operation events for surface BOP systems occur after the BOP stack is attached to the wellhead and has completed a successful test of the connection to the wellbore per the approved well plan. In 2018, 50.7 percent of surface system failures occurred while in operation, approximately the same proportion as in prior reporting years.

Rigs with higher in-operation rig activity have a higher likelihood of experiencing in-operation events. To compare rates of reported in-operation events between rigs, a reporting ratio was calculated for each rig and adjusted using BOP days in-operation as a surrogate measure of rig activity:

$$\text{Adjusted reporting ratio for Rig "A"} = \frac{\text{Rig A's proportion of in-operation events}^{22}}{\text{Rig A's proportion of in-operation BOP days}^{23}}$$

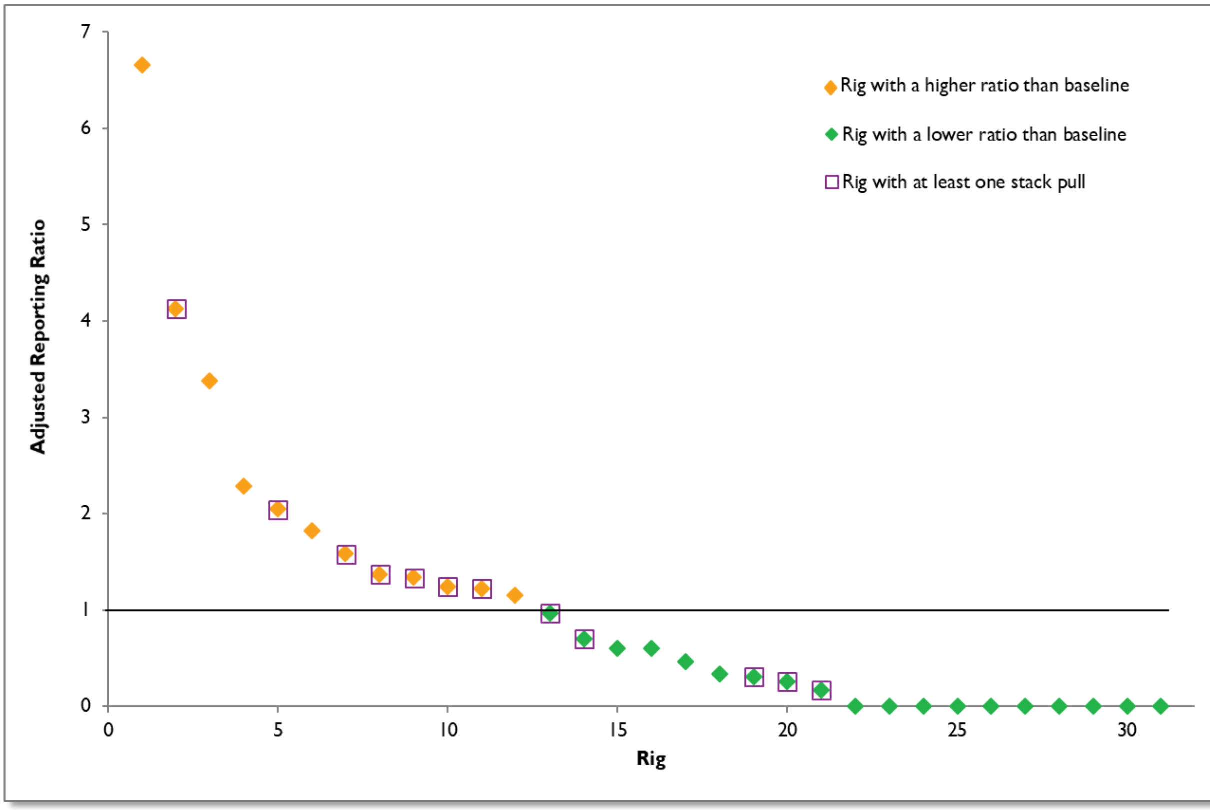
Figure 11 shows the ratio for each rig, calculated using 2017 and 2018 data. The line intersecting the graph at the value of 1.0 represents the baseline reporting ratio where a rig's in-operation event reporting is proportional to its level of activity relative to other rigs with reported events. A ratio greater than 1.0 indicates potentially disproportionately higher reporting of in-operation events, and similarly a ratio less than 1.0 indicates potentially disproportionately lower reporting of in-operation events. As shown in Figure 11, 12 rigs are above the baseline (shown in yellow) and 19 rigs are below it (shown in green).

Figure 11 also shows which rigs experienced stack pulls (shown as an overlaid, outlined shape). Of the 12 rigs with higher relative reporting of in-operation events, seven experienced stack pulls (58.3 percent). Of the 19 rigs with lower relative reporting of in-operation events, five experienced a stack pull (26.3 percent). Considering all stack pulls, the number that occurred on rigs above the baseline (15) was three times the number that occurred on rigs below the baseline (5). This analysis provides support for a proportional relationship between in-operation events and the occurrence of a stack pull (i.e., more in-operation failures found might lead to more stack pulls). However, due to the limited sample size, generalizing this observed pattern to the industry is premature. BTS will conduct additional analysis as more data becomes available.

[22] Rig A's in-operation events divided by the total in-operation events for all rigs.

[23] Rig A's in-operation BOP days divided by the total in-operation BOP days for all rigs with reported events.

Figure 11: Surface System In-Operation Events Relative to Rig Activity, 2017 & 2018



NOTE: Chart includes rigs that reported, via WAR, at least one day of activity in either 2017 or 2018.

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

Surface Stack Pulls

As with subsea systems, a surface BOP stack pull is by definition an unplanned event. By definition, a surface stack pull occurs when a BOP component fails while in operation and requires well conditioning and a mechanical barrier placement to make necessary repairs. The rate of in-operation events leading to stack pulls was compared for all reporting years, as shown in Table 23. Across years, the stack pull rate ranges from 5.6 to 28.6 percent. The table also lists the observed failure for each surface stack pull and the total number of stack pulls in each year associated with that observed failure. Across the reporting years, leaks have been the most common observed failure associated with surface stack pulls.

Table 23: Surface Stack Pull Rates and Observed Failures

Measure	2016	2017	2018	All Years
In-operation events	36	57	35	128
Events leading to stack pulls	2	10	10	22
Stack pull rate	5.6%	17.5%	28.6%	17.2%
Observed failures associated with stack pulls:				
Leakage	0	2	8	10
Fail to seal	0	4	0	4
Internal leak	2	0	1	3
External leak	0	1	1	2
Fail to open	0	2	0	2
Mechanical damage	0	1	0	1

NOTE: Stack pull rate is the number of stack pulls as a percentage of in-operation events. For events reported as *leakage*, the reporter did not specify whether the leak was internal or external.

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

Table 24 shows the subsystems, components, and observed failures for events leading to surface stack pulls in 2018. Eight of the 10 stack pulls were attributed to a leak of the packing element on the annular preventer. Of 12 total leaks involving the packing element on the annular preventer, nine occured while in operation, and eight resulted in a stack pull (88.9 percent). The remaining two stack pull events were attributed to leaks on other components (shown in Table 24), and in both cases the single reported in-operation event resulted in a stack pull.

Table 24: Component Combinations Associated with Reported Surface Stack Pulls

Associated Subsystem	Failed Component	Observed Failure	Total Events	In-operation Events	Stack Pulls
Annular Preventer	Operating System Seal	Internal Leak	1	1	1
	Packing Element	Leakage	12	9	8
Shear Ram Preventer	Bonnet Operating Seal	External Leak	3	1	1
Total			**16**	**11**	**10**

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

Table 25 shows the subsystems, components, and observed failures for events leading to surface stack pulls across all reporting years. For the listed component combinations, 75.9 percent of reported in-operation events led to a stack pull. This finding can be partially attributed to the fact that surface stack equipment is readily available on the rig floor at all times, and that stopping operations to address a component failure typically has low operational and time impacts.

Table 25: Component Combinations Associated with Reported Surface Stack Pulls, 2016-2018

Associated Subsystem	Failed Component	Observed Failure	Total Events	In-operation Events	Stack Pulls
BOP Control Panel	Instrumentation	Mechanical damage	1	1	1
Annular Preventer	Hardware & Mechanical	External leak	3	1	1
	Operating System Seal	Internal leak	3	1	1
	Packing Element	Fail to open	2	2	2
		Leakage	23	15	10
Pipe Ram Preventer	Ram Block Seal	Fail to seal	11	3	1
Shear Ram Preventer	Bonnet Operating Seal	External leak	6	1	1
		Internal leak	1	1	1
	Hardware & Mechanical	Internal leak	2	1	1
	Ram Block Seal	Fail to seal	10	3	3
Total			**62**	**29**	**22**

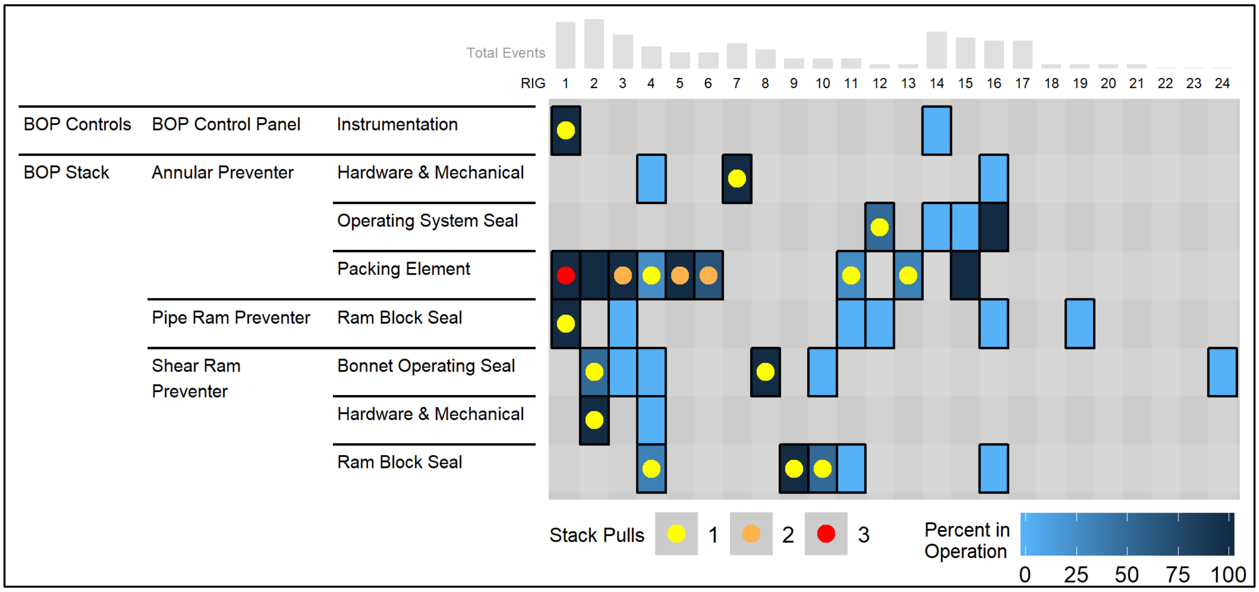
NOTE: The data in this table represent all events that occurred on the identical subsystem, component, and observed failure combination that led to the stack pull. For example, of 23 failures involving leakage on the packing element on the Annular Preventer, 15 were in-operation events and 10 resulted in a stack pull.

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

Figure 12 offers a visual representation of the distribution of components involved in in-operation events leading to at least one stack pull between 2016 and 2018, by rig. The shading of each grid square shows whether the listed rig (i.e., column) experienced a failure event for the listed component (i.e., row). Blue shading represents the proportion of in-operation events relative to total reported events for that component, with darker blue representing higher rates of in-operation events. Dots represent stack pull events. Unshaded (gray) grid squares indicate the rig experienced no reported failure events for the listed component.

As the figure shows, squares with a stack pull generally have a darker shade (higher in-operation ratio), and squares without a stack pull generally have a lighter shade (lower in-operation ratio). More precisely, for component combination events associated with a stack pull (i.e., all squares showing a stack pull) 66.7 percent were in-operation events, while only 10.7 percent of events with no stack pull occurred in operation. This points toward an increased likelihood for a stack pull on rigs with a higher proportion of in-operation events.

Figure 12: Components Involved in In-Operation Events Leading to a Stack Pull, by Rig, 2016-2018



NOTE: Rigs shown experienced at least one reported event involving the listed component combination.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

In addition to the surface stack pull rate, which is measured as a percentage of in-operation events, surface stack pulls were examined as a percentage of successful stack "starts," i.e., the total number of times a surface stack was assembled on the wellhead and went into operation. This is referred to in the industry as "rigging up" the BOP. In 2018, there were 10 surface stack pulls and 217 successful stack starts (see Table 18), meaning 4.6 percent of successful stack starts eventually led to a stack pull.

Investigation and Failure Analysis (I&A)

As for subsea system events, the root cause for most surface system events can be easily discerned, and the component can be repaired, replaced, or otherwise corrected; the level of I&A required for such events is referred to as "cause immediately known."[24] For the remaining events, further I&A is required to determine the root cause. For all reporting years, the percentage of events with I&A completed

[24] See section 9.0 of the SafeOCS well control failure reporting guidance document: *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.

beyond the level of cause immediately known is shown in Table 26. Overall, the share of surface system events with further I&A has decreased each year, though only slightly from 2018 to 2017.

Table 26: Investigation and Analysis of Surface System Events

Year	Total Events	Events with Further I&A
2016	760	66 (8.7%)
2017	1,307	67 (5.1%)
2018	1,127	39 (3.5%)
Total	**3,194**	**172 (5.4%)**

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

Root Causes of Surface System Events

Table 27 compares the distribution of root causes across all reported events for each year and the percent of each root cause determined through further I&A. As shown in the table, *wear and tear* and *other* have consistently been determined as the top two root causes, with the share of events attributed to *wear and tear* increasing each year and the share attributed to *other* decreasing each year. Overall, the percentage of root causes determined through further I&A decreased from 2016 to 2018 for all root causes except *design issue*. The limited number of surface system events reported so far prevents generalization of these observations. BTS will conduct additional analysis as more data becomes available.

Table 27: Surface System Event Root Causes

Root Cause	Percent of All Events			Determined through Further I&A		
	2016	2017	2018	2016	2017	2018
Wear and Tear	19.4%	46.5%	56.5%	61.5%	7.5%	10.3%
Maintenance Error	10.4%	2.6%	7.2%	57.1%	66.7%	0.0%
Design Issue	3.0%	2.6%	7.2%	0.0%	0.0%	80.0%
QA/QC Manufacturing	3.0%	3.5%	4.3%	50.0%	25.0%	0.0%
Procedural Error	1.5%	6.1%	1.4%	100.0%	85.7%	0.0%
Documentation Error	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%
Other*	61.2%	38.6%	23.2%	9.8%	4.5%	6.3%

NOTE: *The selection of *other* by the submitter allows for entry of a root cause that may not precisely fit the other selections. Most submitted root causes under *other* have been *RCFA required*.

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

Root Causes of Surface Stack Pulls

As for subsea system events, RCFAs by the OEM or third party are expected to be carried out for surface system events resulting in stack pulls and reoccurring failures.[25] RCFA documentation was sent to SafeOCS for one of the ten surface stack pulls reported in 2018, as shown in Table 28. The root cause of the event with submitted RCFA documentation was *wear and tear*. For the remaining nine, the listed root cause was *wear and tear* (6), *QA/QC manufacturing* (1), or *not determined* (2). Without submission of additional RCFA documentation, the suspected root cause of the latter nine events cannot be confirmed.

Table 28: Root Causes of Surface Stack Pulls

Associated Subsystem	Failed Component	Root Cause	RCFA Status	Stack Pulls
Annular Preventer	Operating System Seal	Wear and Tear	Not sent to SafeOCS	1
	Packing Element	Not Determined	Not sent to SafeOCS	1
		QA/QC Manufacturing	Not sent to SafeOCS	1
		Wear and Tear	Not sent to SafeOCS	5
			Completed	1
Shear Ram Preventer	Bonnet Operating Seal	Not Determined	Not sent to SafeOCS	1
Total				**10**

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

Table 29 summarizes the subsystem, component, and root cause for all surface stack pull events during 2016 to 2018. RCFA documentation was sent to SafeOCS for five of the 22 total events.

[25] See section 9.0 of the SafeOCS well control failure reporting guidance document: *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.

Table 29: Root Causes of Surface Stack Pulls, 2016-2018

Associated Subsystem	Failed Component	Root Cause	RCFA Status	Stack Pulls
BOP Control Panel	Instrumentation	Not Determined	Not sent to SafeOCS	1
Annular Preventer	Hardware & Mechanical	Procedural Error	Completed	1
	Operating System Seal	Wear and Tear	Not sent to SafeOCS	1
	Packing Element	Design Issue	Not sent to SafeOCS	2
		Maintenance Error	Completed	1
		Not Determined	Not sent to SafeOCS	1
		QA/QC Manufacturing	Not sent to SafeOCS	1
		Wear and Tear	Not sent to SafeOCS	5
			Completed	1
Pipe Ram Preventer	Ram Block Seal	Wear and Tear	Completed	2
Shear Ram Preventer	Bonnet Operating Seal	Not Determined	Not sent to SafeOCS	2
	Hardware & Mechanical	Not Determined	Not sent to SafeOCS	1
	Ram Block Seal	Wear and Tear	Not sent to SafeOCS	3
Total				**22**

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

Wear and tear was determined to be the root cause for 12 surface stack pull events in 2018, and RCFA documentation was sent to SafeOCS for only three of these events. Of the 12 wear and tear events, half listed the failed component's age, which ranged from one month to 19 months. The date since last maintenance was also listed, and all had maintenance completed within the last eight months. While wear and tear may be a reasonable root cause selection for each of these events, without the required RCFA information, it is unknown whether a more thorough investigation would have yielded different results than those initially reported.

Lessons Learned

Of nine surface system events with further I&A in 2018, two contained documentation listing follow-up actions addressing each root cause, summarized in Table 30. One of the I&As contained findings applicable to two other similar reported events, bringing the total number of surface system events with listed follow-up actions to four. As with I&As completed for subsea system events, developing and communicating follow-up actions can have the potential for industry-wide safety improvements.

The identified follow-up actions within documentation submitted to SafeOCS included a product redesign, a maintenance procedure change, and the installation of a different component part. The listed actions serve as examples of how RCFAs can lead to improvements that might prevent reoccurring events, as the first listed follow-up action affects three events.

Table 30: Follow-Up Actions on Surface System Events

	Component	Root Cause	Root Cause Details	Recommended Follow-up Action
1	Hydraulic Stab	Design Issue	Quick Disconnect (QD) misalignment due to inadequate communication from supplier.	Rig owner should conduct a product redesign, to use hoses instead of tubing to transmit BOP hydraulic signals directly to the BOP. Operator should implement a maintenance procedure change, to implement a process for tracking rotating assets.
2	Ram Block Seal	Design Issue	A new ram rubber design was installed, and they required tighter cavity dimensions.	OEM installed a thicker than normal lower skid plate.

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

Chapter 4: Conclusion and Next Steps

Aggregated analysis of well control equipment component failure data can be used to develop a more robust and comprehensive understanding of the nature of failures, their root causes and contributing factors, and event trends across the industry. This information can be used to make changes to current practices and improve safety and equipment reliability.

Key findings from this report include the following:

- The amount of rig activity in the GOM increased from 2017 to 2018, while the number of failure events reported to SafeOCS decreased.
- From 2016 to 2018, the rate of event reporting adjusted for rig activity has decreased each year, due to fewer reported events and more rig activity (as measured in BOP days).
- Leaks have remained the most frequently reported observed failure, and wear and tear has remained the most frequently reported root cause of failure events, from 2016 to 2018.
- While the rate of stack pulls has fluctuated from year to year for both subsea and surface systems, completion of RCFAs for stack pulls has remained under 50.0 percent, despite the requirement of an RCFA for every stack pull.
- Overall, the percent of events with additional information submitted on causal factors via an investigation and failure analysis has decreased each year.

Next Steps: Opportunities for Improving Data Quality and Access

Collecting more detailed, accurate, relevant, and timely equipment failure data can support more in-depth statistical analyses to inform industry safety improvement efforts. SafeOCS continues to focus on improvement efforts in the following areas:

Data collection: With continued input from the IADC/IOGP BOP Reliability JIP, SafeOCS is continuing to refine the data collection form to capture more detailed and accurate information. Objectives of this work include updated definitions, improved drop-down choices in data fields, and an updated form, containing more fields targeting root cause and follow-up information.

SafeOCS will continue to seek more timely and complete information on RCFAs as required under 30 C.F.R. 250.730(c)(2). Improved RCFA information will improve the quality of SafeOCS data and, in turn, the quality of the analysis the SafeOCS program can perform. More thorough investigations, particularly on events leading to stack pulls, may provide information that can allow operators and equipment owners to prepare better maintenance and testing plans to suit the anticipated operational conditions to which the BOP stack will be subjected. Better information will also be captured by ensuring operators can adequately explain the root cause determination when it falls under *other*, and BTS will evaluate how this element of the data collection could be improved.

Data processing: Currently, operators still submit event notifications in several formats, including PDF documents, Excel summaries, and SafeOCS website forms, the latter being the preferred method. With a continued emphasis on electronic formats, more event notifications have been submitted via Excel summaries and the SafeOCS online form, improving the processing of multiple event notifications and reducing data entry errors.

Data harmonization: Evaluation of well operations data within the BSEE WAR database indicated inconsistencies in some cases between the information in event notifications and the daily summaries within WARs. These inconsistencies can lead to inaccurate categorizations of data, potentially leading to inaccurately estimating the number of failures when the BOP is in operation. SafeOCS is exploring more data sources to inform exposure measure statistics that will allow for cross-comparison with the goal of accurate denominator information and the definitional precision of data submitted to the SafeOCS database.

Data access: In addition to annual reports and highlight publications, SafeOCS has also developed an online interface where operators and the public can view a data dashboard containing various aggregated, anonymized statistics. Once there is sufficient data available, SafeOCS plans to expand the dashboard allowing for more user interaction with the data. This tool allows for continuous access to essential analysis of the most recently available data, including total submissions, on-time reporting, types of failures reported, and root causes.

APPENDIX A: THE BSEE WELL CONTROL RULE

BSEE's Well Control Rule (WCR) went into effect on July 28, 2016 and BTS began collecting notifications of blowout prevention equipment component failures shortly thereafter. The WCR defines an equipment failure as "*any condition that prevents the equipment from meeting the functional specification*" and requires reporting of such failures.[26] More specifically, pursuant to 30 CFR 250.730(c), operators must do the following:

(1) Provide a written notice of equipment failure to the Chief, Office of Offshore Regulatory Programs, and the manufacturer of such equipment within 30 days after the discovery and identification of the failure.

(2) Ensure that an investigation and a failure analysis are performed within 120 days of the failure to determine the cause of the failure. Any results and corrective action must be documented. If the investigation and analysis are performed by an entity other than the manufacturer, the Chief, Office of Offshore Regulatory Programs and the manufacturer receive a copy of the analysis report.

(3) If the equipment manufacturer sends notification of any changes in design of the equipment that failed or the operator changes in operating or repair procedures as a result of a failure, a report of the design change or modified procedures must be submitted in writing to the Chief, Office of Offshore Regulatory Programs within 30 days.

(4) You must send the reports required in this paragraph to: Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, VA 20166.

Per the agreement between BSEE and BTS, all notifications related to equipment failure should be submitted to BTS.

Note: In 2019, BSEE revised various provisions of the Well Control Rule requirement including revisions to 250.730(c) to clarify that failure notifications must be sent to BTS as BSEE's designated third party. 84 Fed. Reg. 21,908 (May 15, 2019).

[26] 30 CFR 250.730(c)(1).

Appendix B: Confidential Information Protection and Statistical Efficiency Act of 2002 (CIPSEA)

The confidentiality of all data submitted to SafeOCS is protected by the Confidential Information Protection and Statistical Efficiency Act of 2002 (CIPSEA). However, data submitted directly to BSEE are not protected by CIPSEA. Data protected under CIPSEA may only be used for statistical purposes. This requires the following: a) only summary statistics and data analysis results will be made available; b) microdata on events collected by BTS may not be used for regulatory purposes; and c) information submitted under this statute is also protected from release to other government agencies including BSEE, as well as protection from Freedom of Information Act (FOIA) requests and subpoenas.

Appendix C: Glossary

Active Operators: Operators which conducted drilling or non-drilling rig activity in the GOM OCS during the listed time period.

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

Blind Shear Ram (also, Shear Ram): A closing and sealing component in a ram blowout preventer that first shears certain tubulars in the wellbore and then seals off the bore or acts as a blind ram if there is no tubular in the wellbore.

Blowout Preventer (BOP): A device installed at the wellhead, or at the top of the casing, to contain wellbore pressure either in the annular space between the casing and the tubulars or in an open hole during drilling, completion, testing, or workover.

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 (BOP Controls): The system of pumps, valves, accumulators, fluid storage and mixing equipment, manifold, piping, hoses, control panels, and other items necessary to hydraulically operate the BOP equipment.

BOP Days: A measure which offers an approximation of rig activity, or the time period (in days) when an equipment component failure could have occurred. To measure rig activity, SafeOCS analyzes WAR data to calculate the number of days rigs are active during a given time period. Some rigs have more than one BOP stack, and the days of activity on a rig is adjusted to account for the number of BOP stacks, resulting in the final measure, BOP days.

BOP Stack: The assembly of well control equipment including preventers, spools, valves, and nipples connected to the top of the wellhead, or top of the casing, that allows the well to be sealed to confine well fluids. A BOP stack could be a subsea stack (attached to the wellhead at the sea floor), or a surface stack (on the rig or non-rig above the water).

BOP Stack Pull (Subsea): When either the BOP is removed from the wellhead or the LMRP is removed from the lower stack to repair a failed component. The BOP stack cannot be classified as a stack pull until after it has been in operation as defined above.

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

BOP Stack Pull Event Rate: See *Event Rate*.

BOP Stack Retrieval: The recovery of the LMRP and or the subsea BOP stack before it has been classified as in operation. If the LMRP and/or BOP stack is recovered to the rig floor any time after deployment has begun and before initial latch-up tests are passed, it is considered a stack retrieval.

BOP Stack Run (or Deployment): The activity of deploying, or "running" a subsea BOP stack from the rig (or non-rig) floor to the subsea wellhead. A stack run can take approximately 8 to 48 hours, depending on water depth. The term stack run and stack deployment are equivalent and interchangeable. In this report, the term "successful BOP stack run" means the BOP passed its initial latch-up testing and went into operation.

BOP Stack Start (or Rig Up): In this report, BOP stack start means when a surface BOP stack is assembled on the wellhead. This is referred to in the industry as "rigging up" the BOP. In this report, the term "successful BOP stack start" means the BOP passed its initial testing and went into operation.

Control Fluid: Hydraulic oil, water-based fluid, or gas which, under pressure, pilots the operation of control valves or directly operates functions.

Disabled Barrier: When a barrier is not able to perform its intended function (for example, a failure that causes an annular preventer to fail to seal or fail to open or close).

Drilling Fluid: The fluid added to the wellbore to facilitate the drilling process and control the well. Various mixtures of water, mineral oil, barite, and other compounds may be used to improve the fluid characteristics (mud weight, lubricity, etc.). This is commonly called drilling mud, and it may contain drilling cuttings.

Drilling Operations: Rigs primarily perform drilling and completion operations but can also perform operations typically performed by less expensive non-rigs such as well intervention, workover, temporary abandonment, and permanent abandonment. These activities are considered non-drilling operations and are typically performed by non-rig units such as coil tubing units, hydraulic workovers, wireline units, plug and abandon (P&A) units, snubbing units, and lift boats.

Event Rate: The event rate reflects the number of reported events per 1,000 BOP days. The event rate is calculated as: (events / BOP days) * 1,000.

> **In-Operation Event Rate:** The in-operation event rate reflects the number of in-operation events per 1,000 in-operation BOP days. The in-operation event rate is calculated as: (in-operation events / in-operation BOP days) * 1,000.
>
> **Not-in-Operation Event Rate:** The not-in-operation event rate reflects the number of not-in-operation events per 1,000 not-in-operation BOP days. The not-in-operation event rate is calculated as: (not-in-operation events / not-in-operation BOP days) * 1,000.
>
> **Stack Pull Event Rate (or Stack Pull Rate):** Two measures are used for stack pull event rate, defined below. In this report, the term typically refers to measure (b), except in Table 3: Subsea System Exposure Measures and Table 18: Surface System Exposure Measures, where the term refers to measure (a).
>
> a. The number of stack pulls per 1,000 in-operation BOP days, i.e., (stack pulls / in-operation BOP days) * 1,000.
>
> b. The number of stack pulls as a percentage of in-operation events, i.e., (stack pulls / in-operation events) * 100.

In-Operation (Subsea): A subsea BOP stack is in-operation after it has completed a successful pressure test of the wellhead connection to the well-bore per approved well plan.

In-Operation (Surface): A surface BOP stack is in-operation after it has completed a successful pressure test of the wellhead connection to the well-bore per approved well plan.

In-Operation Event Rate: See *Event Rate*.

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

Non-Drilling Operations: Operations that are considered "non-drilling" include intervention, workover, temporary abandonment, and permanent abandonment. These activities are typically performed by specialist equipment that is installed on either a rig or non-rig.

Not-in-Operation (Subsea): A subsea 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 or pulled (retrieving), it is considered not-in-operation.

Not-in-Operation (Surface): A surface BOP changes from in-operation to not-in-operation when the well is conditioned and a mechanical barrier (i.e., packer/plug) is set in the wellbore.

Not-in-Operation Event Rate: See *Event Rate*.

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 time period preceding the start of drilling activities.

Rig Days: A measure which offers an approximation of rig activity, or the time period (in days) when an equipment component failure could have occurred. To measure rig activity, SafeOCS analyzes WAR data to calculate the number of days rigs are active during a given time period.

Rigs Operating: This includes any rigs in the given time period and location which had an active contract to perform drilling and non-drilling activities.

Stack Pull Event Rate: See *Event Rate*.

Subunit: See *Well Control Equipment Subunits*.

Wellbore Fluid: The fluids (oil, gas, and water) from the reservoir that would typically be found in a production well, commonly referred to as hydrocarbons. During drilling, completion, or workover operations, drilling fluids may also be referred to as wellbore fluids.

Well Control Equipment Subunits: The 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.

Wells Spud: The number of wells that were first started, or "spudded", in the given time period, beginning January 1st and ending December 31st. Wells spudded are a subset of total wells with activity in a given time period.

Wells with Activity: This includes any well which had a rig or non-rig performing drilling or non-drilling activities in the given time period beginning January 1st and ending December 31st.

APPENDIX D: ACRONYM LIST

ANSI: American National Standards Institute

API: American Petroleum Institute

BOP: Blowout preventer

BSEE: Bureau of Safety and Environmental Enforcement

BTS: Bureau of Transportation Statistics

CIPSEA: Confidential Information Protection and Statistical Efficiency Act

DOI: Department of the Interior

DOT: Department of Transportation

EHBS: Emergency hydraulic backup system

GOM: Gulf of Mexico

I&A: Investigation and failure analysis

IADC: International Association of Drilling Contractors

IOGP: International Association of Oil and Gas Producers

JIP: Joint industry project

LMRP: Lower marine riser package

LOC: Loss of containment

MOC: Management of change

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

WCR: Well Control Rule

Appendix E: Relevant Standards

Industry standards with relevant sections incorporated by reference in 30 CFR 250.198:

- API RP 17H, Remotely Operated Tools and Interfaces on Subsea Production Systems, Second Edition
- ANSI/API Spec. 6A, Specification for Wellhead and Christmas Tree Equipment, Twentieth Edition
- ANSI/API Spec. 16A, Specification for Drill-through Equipment, Third Edition
- ANSI/API Spec. 16C, Specification for Choke and Kill Systems, First Edition
- API Spec. 16D, Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment, Second Edition
- ANSI/API Spec. 17D, Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment, Second Edition
- ANSI/API Spec. Q1, Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry, Ninth Edition
- API Standard 53, Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition

Appendix F: Schematics of BOP System Boundaries

Figure 13: Example Choke and Kill Manifold for Subsea Systems

See Appendix C, Figure 18 in 2016 SafeOCS Annual Report.

Figure 14: Example Subsea BOP Stack with Optional Locations for Choke and Kill Lines

See Appendix C, Figure 19 in 2016 SafeOCS Annual Report.

Figure 15: Example Subsea Ram BOP Space-Out

See Appendix C, Figure 20 in 2016 SafeOCS Annual Report.

Figure 16: Example Surface BOP Ram Space-Out

See Appendix C, Figure 21 in 2016 SafeOCS Annual Report.